Geomechanical and thermal reservoir properties in Dutch geothermal plays

Measurements, upscaling and calibration guideline

May 2026

This document was created as a part of the TKI Geo Energie project Properbase, Subsidy scheme TKITOE-Gas, Project number TKITOETKI2021-04-GE

EBN B.V.
Daalsesingel 1
3511 SV Utrecht
The Netherlands

Telefoon: +31 30 233 9000
E-mail: ebn.mail@ebn.nl
Website: www.ebn.nl

KvK-nummer : 14026250
BTW-nummer: NL001726614B01

Main author:

Wouter van der Zee	EBN

Contributing authors:

Sjoukje de Vries	EBN
Jasper Kwee	IF Technology
Quinten Boersma	IF Technology
Nick Buik	IF Technology

Contents

1 Introduction

The ambition of the geothermal industry is to build 700 geothermal energy projects in the Netherlands by 2050 (Masterplan geothermal energy, 2018). This means that the use of hot sedimentary aquifers that are currently used must be expanded. But also that suitable reservoirs have to be found in more distant areas or deeper in the subsurface. For the latter, significantly less data are available.

Geomechanical and thermal properties of target reservoirs are poorly known. Both of these properties are needed for accurate reservoir character prediction and to ensure safe and economic project performance. However, most of the data available for subsurface prediction originates from the hydrocarbon industry, which are not always in the locations most suitable for dense installation of geothermal heat plants, while in so-called "white spots" data are scarce (EBN, 2019).

Geothermal projects do not generally generate rich datasets and it is seen that this lack of data slows down the increase in number of geothermal doublets. It is often impossible to predict rock properties with sufficient accuracy to evaluate geothermal project performance, due to lack of awareness of appropriate data methodologies to convert downhole log data to rock properties. Improper data conversion methodologies and lack of data acquisition also hampers proper well test evaluation, as accurate petrophysical property evaluation is needed as an input. This is a key reason for large or unknown uncertainties in, for example, flow and geothermal power output predictions, project longevity, as well as in quantifying the risks of induced seismicity or seal fracturing.

This report is one of the deliverables of the TKI project ProperBase.[1] ProperBase has as a goal to quantify and reduce the uncertainties as described above. The project has a measuring component producing data and geological understanding , a correlating component, linking rock properties to petrophysical log data by various innovative means, and an implementation component setting the findings into geomodel application. This last part is described in this report.

1.1 Objective of this report

The objective of this report is to describe guidelines how to obtain the most appropriate input parameters that can be used in geomodel applications which are used by the Dutch geothermal industry (DoubletCalc, SRIMA). This report includes upscaling and calibration techniques going from core, log and well test data to data suitable for production estimations, cap rock integrity and seismic risk assessment focused on flow, geomechanical and thermal properties.

This upscaling guideline is meant as a guideline only and does not replace professional judgement. This is not meant as an official rulebook, nor can any rights be derived from it. It is meant purely as a guideline of how upscaled reservoir parameters can be derived in a consistent matter. It should be noted that official bodies, such as the Ministry of Climate Policy and Green Growth, Staatstoezicht op de Mijnen and TNO-AGE, are not bound by these guidelines.

1.2 Structure of this document

The rest of this document consists of 4 chapters.

[1] The TKI ProperBase project is funded by RVO, with the program Geo-Energie within the TKI Nieuw GAS

2) Introduction and background
3) General workflow from core plug to reservoir properties.
4) Specific workflow and techniques for parameters most used in geothermal exploration and exploitation.
5) Data gathering for geothermal systems.

Chapter 2) is an introduction to measurements, uncertainty and upscaling. In 3) we look at a general ideal workflow from core to reservoir properties. This chapter describes the possibilities and points of attention going from scale to scale. However, no parameter specific techniques are described. In 4) the most important parameters for geothermal exploration and exploitation are discussed. This chapter describes for each important parameter the possibilities of upscaling and calibration. It should be noted that detailed workflows and equations are gathered in appendices for readability. In 5) we summarize the data gathering. Based on this we propose a minimal data gathering methodology to improve production strategies and support risk assessment for geothermal initiatives.

The audience of this document is two-fold. Chapters 2 and 3 are for those who are active in geothermal exploration/exploitation and have a high-level background knowledge, but may contain information that is well known to more specialist readers. Chapter 4 dives deeper into the technical background and targets those with a technical subsurface background. Chapter 5 is for both audiences, where especially Table 4 is a good summary for both those with only high level background knowledge and specialists. Due to the this two-fold approach there might be some repetition in the text, especially in chapters 3 and 4.

1.3 Acknowledgements

This TKI ProperBase project is a part of the TKI Geo Energie project Properbase, Subsidy scheme TKITOE-Gas, Project number TKITOETKI2021-04-GE.

We like to thank Phil Vadron, Hemmo Abels, Auke Barnhoorn and Parvin Kolah Kaj of TU Delft for discussion and their input for the document. We also thank two anonymous reviewers who provided a review on an earlier version of this document which helped to improve this final version.

2 Introduction

Subsurface data is very important in geothermal exploration and exploitation as it allows accurate reservoir character prediction which can ensure safe and economic project performance. Practically, in the situation of the Netherlands, operators need to have a good understanding of the subsurface to be able to estimate the performance for SDE+ subsidy applications, project financing and to estimate the seismic risk and cap rock integrity for the start and follow-up licenses (startvergunning aardwarmte and vervolgvergunning aardwarmte) applications.

2.1 Subsurface measurements are sparse in time and space

Working in the subsurface implicitly involves sparse direct measurements in time and space. Even if a subsurface project measures as much data as possible, it will always be limited to few direct measurements (e.g. on core samples), wire line or LWD[2] logging along the well path combined with 3 or 4D seismic and seismic monitoring. Continuous measurement are normally limited to well head pressures and flow. In this respect, it should be noted that geothermal projects typically do not even generate such rich datasets.

The sparse nature of subsurface data leads to the situation that for modelling subsurface activities, gaps need to be filled in space and time. This means that the limited available data must be converted, inter- and extrapolated and upscaled to one or more static models (of properties) that can be used in dynamic simulations. This process crosses many different spatial scales from core plug to full reservoir scale.

2.1.1 Observations on different scales

Subsurface observations are done at many different scales. Each scale has its own observation technique and related resolution. It should be noted that the boundaries of the scales are not hard defined. For example, it is possible to make an observation on plugs or cavings at a microscopic scale using a SEM or microscope. But on the same samples, a macroscopic description can be made at plug scale. An overview of the different scales at which observations can be made on geothermal reservoir evaluation is given below.

Microscopic scale

This refers to the scale of grains and cement at the grain contacts. Observations at this scale help to determine properties, e.g. microporosity, or identify diagenetic processes that impact plug scale properties, for example porosity, permeability or mechanical properties. Resolution is from µm to cm scale.

Plug scale

This refers to rock plugs taken from drill core or the sidewall of the well. The properties of these plugs can be tested in the laboratory for their flow, geomechanical and thermal properties. Resolution is on cm-scale. A special case are cuttings and cavings. These small pieces of rock are the result of the drilling process and can be used for rock description and mineralogy measurements.

[2] LWD = Loging while drilling. LWD is a technique where wellbore measurements are taken during the drilling operation. The data can be transmitted in real time or are stored as memory data in the bottom hole assembly.

Core scale

Whole cores can be used for, for example, (litho)facies evaluation and the related heterogeneity evaluation. Whole core testing is technically possible, but rarely done due to the limited availability of core. Resolution is at cm to 10m scale in 1D.

Log-scale

This refers to wireline log or LWD (logging while drilling) scale. An ideal log-suite covers the entire reservoir section and overburden/seal section, with preferably the entire overburden as well. Logs can be calibrated by core and sidewall plugs. Resolution is at cm to m scale.

Well-test scale

This refers to the results of well tests. Those test give a single value for the whole reservoir section connected to the test and provide some insights in the surroundings of the well within a certain horizontal penetration depth depending on the type and length of the test . The vertical resolution can be improved when tests are performed in which parts of the well can be isolated, or if gradients in the well can be measured during a test. For Instance, adding a spinner test can increase vertical resolution. Typical tests are production or injection tests, but also vertical seismic profiling (VSP) can be seen as a test well scale. Resolution is from 10m to 100m.

Reservoir scale

As soon as we go further away from the wellbore then we observe at reservoir scale. Typical methods to obtain information at this scale are seismic investigations which allow structural information on the reservoir to be determined. Advanced seismic processing allows for seismic attribute analyses. Resolution is 100m to kms.

2.1.2 Uncertainties due to sparsity of geological measurements

This guideline describes the workflow how to determine the most appropriate input values for geomodels that are used to calculate, for example, power estimates, production forecasts and thus business cases. However, choosing a single perfect input parameter is not possible. Every value will have related uncertainty. In addition to the uncertainty due to the measurement technique or evaluation, uncertainty also results from the inherent heterogeneity of subsurface layers in combination with non-continuous sampling of such layers.

As an example, we describe the workflow to determine reservoir flow parameters for a geothermal doublet. If cores are available, the permeability can be measured on core plugs. However, these measured values are not necessarily representative for the whole interval, because rock properties commonly display heterogeneities on various scales, driven by lithology, sedimentary structures, bedding and variability and diagenetic differences such as faulting, fracturing and cementation or dissolution of minerals. Therefore, a measured value such as a core plug measurement) is almost certainly different when the measurement is performed at a different location in the reservoir. In other words: even if one or more direct measurements are available, the derived reservoir-scale parameters have always an uncertainty bandwidth.

To derive a representative value for a reservoir interval, we need to upscale the measured plug values to the whole interval by using the well logs and appropriate upscaling techniques. In this process of going from cm-scale to reservoir scale, spatial resolution is lost. The uncertainties will increase due to the loss in resolution during these upscaling steps. For example, thin clay bands can have a profound effect on the flow perpendicular to these bands, but upscaling will “remove” these

bands and give an averaged value for the formation. The information on directional impact and the exact location of these bands is lost through the upscaling. To check if the upscaling has led to reliable values we check it with the results of a well test. However, evaluating well tests results comes with its own challenges and the inferred permeability also has an uncertainty. .

The amount of uncertainty (uncertainty bandwidth) depends on the amount and quality of the data. Even in the case of a "complete" dataset, there will always be an uncertainty bandwidth due to the heterogenous nature of the subsurface. However, a "complete" dataset will help to quantify the (hopefully, relative narrow) bandwidth. But in certain cases, the data situation might be such that it is even not possible to quantify the uncertainty because there is only limited data available and/or absence of core plug measurements. In those cases only a qualitative description can be given.

2.1.3 How to handle uncertainties?

As described above, the nature of subsurface engineering requires inclusion of uncertainty. Why is it important to quantify the uncertainty and to reduce it where possible? The importance of the uncertainty bandwidth becomes visible when decisions are not made on the most probable value of a parameter or calculated risk, but are made on a certain probability value, such as the P90 or P95.

To illustrate this, we can look at how different parties handle a certain calculated risk. Figure 1 gives a schematic visualization of risk calculation and norm or criterion acceptance. In this risk calculation, all uncertainties of the input parameters to calculate the likelihood and effects are taken into account. This will lead a calculated risk with uncertainty bandwidth as displayed in a). Often the most probable value (mean or median) is reported as the risk. This reported risk might be below the norm or criterion (set by e.g. a government or company).

However, if for some reason it is not practically possible to take the uncertainties into account for all input parameters, or are if the uncertainties are poorly quantified, one might want a higher confidence that the norm or criterion will not be exceeded and request that the P95 (or more) stays below the norm or (as visualized in b).[3] This means that narrowing the uncertainty range may be necessary to ensure that the norm or criterion can be respected.

The example above can be applied on safety risks, but also on economic risks. Different organizations with different roles might treat the same calculated economic project risk differently depending on the uncertainty distribution. It might be that an operator finds the economical project risk acceptable (and judges against the mean), where the financing company wants a higher degree of security before investing in the project (and judges against, e.g., the P90).

[3] An example of this can be found in the letter of SodM to the ministry of EZK on fracturing the cap rock where it states that 10% of calculated scenarios exceeding the norm is not acceptable because not all uncertainties are incorporated in the calculations: https://www.sodm.nl/binaries/staatstoezicht-op-de-mijnen/documenten/publicaties/2024/04/19/achtergrondinformatie-benodigde-informatie-voor-advisering-aardwarmtevergunningen-sodm/3+SDRA+en+SRIMA+methodiek+en+tool+EZK+dd+onbekend+ontvangen+door+SodM+op+21+augustus+2023+kenmerk+onbekend+kenmerk+SodM+27399885.pdf.

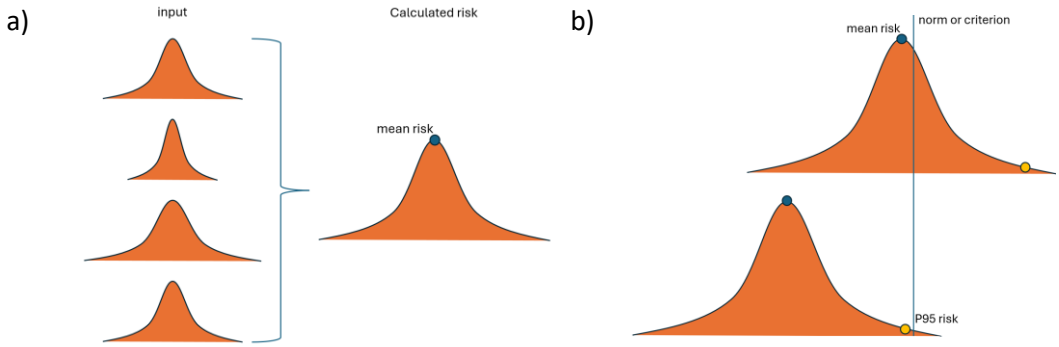


Figure 1: Schematic visualization of risk calculation and norm or criterion acceptance.

a) Risk calculation with input parameters which have each their own uncertainty bandwidth leading to a calculated risk value with associated uncertainty

b) The acceptance of calculated risk and associated uncertainty might be depending per organization. In the example above it might be that even though the calculated mean risk is below the norm or criterion, this is not acceptable, as the norm or criterion is set at the P95 risk. This can only be achieved if the overall risk is much lower (bottom picture).

Therefore, it is recommended to not only determine the most probable value for your analyses but also to provide the estimated uncertainty for that value.

Some of the commonly used tools in the geothermal sector in the Netherlands (DoubletCalc[4], SRIMA[5]) have an uncertainty analysis included. These analyses require data to be input with the most probable value, together with a minimum and maximum value. Therefore, we have to quantify the uncertainty in all input parameters to be able to give a realistic range and obtain a solid answer from these tools.

2.2 Upscaling

2.2.1 What is upscaling, and why are we doing it?

As described above, upscaling is an important step in choosing the most appropriate value which can be used in geomodelling applications. Upscaling, in general terms, is the process to assign a summary value from a larger set of values. It is the process of determining a single, representative value from a larger number of observations on a finer scale.

What we mean by this in the context of this guideline is: how can we determine a single, representative property value from a set of property values measured on a smaller scale? For example, how can we distill one porosity value, representative for an entire, specific reservoir interval from a set of wireline measurements? Ideally, the upscaled value should be given including an uncertainty range, resulting in for example, a minimum, median and maximum value.

In practice, upscaling is required, for instance, to establish the values required for input in power calculation software (for example, DoubletCalc) or for input in seismic hazard and risk or seal integrity assessments (for example, SRIMA). Many of these tools work with homogeneous rock descriptions to allow the use of analytical solutions, which lead to faster calculations. The fact that some properties (e.g. permeability) are directional has to be taken care of in the upscaling process.

[4] https://www.nlog.nl/en/tools
[5] https://www.nlog.nl/sdra-geothermie-integriteit-afdichtend-pakket

2.2.2 Upscaling experience in other subsurface disciplines

Upscaling cm to meter scale core and logging data to reservoir scale is commonly done in hydrocarbon exploration and exploitation. The largest difference with the geothermal sector is that in the hydrocarbon industry there is normally more data available. Based on these rich datasets, the oil and gas sector has developed workflows how to build 3D geological models consisting of many cells based on structural information, calibrated well data and in some cases supported by 3D seismic attributes.[6] For flow modeling, these finer-scale geological models are upscaled to larger grid cells so flow simulations can be performed in a reasonable timeframe.

In geothermal exploration and exploitation there is often far less info, and building full-blown 3D models using above techniques is not a realistic option most of the time. Therefore, this guideline is not dedicated to upscaling for use in flow models consisting of numerical cells as described above. There are several excellent textbooks on that subject matter.[7]

For 3D geomechanical calculations, the geological models are enriched with mechanical material properties. The workflows for geomechanical modeling are less mature than those for flow modeling. Some workflows allow heterogenous distributed mechanical properties (e.g. based on interval velocity cubes) which are upscaled to individual cells, other work with homogeneous mechanical material properties per identified layer or fault block.

[6] An example of a text book describing the geological modelling is: Shared earth modeling by John R Fanchi https://doi.org/10.1016/B978-0-7506-7522-2.X5000-9

[7] For example: Reservoir Model Ringrose & Bentley https://doi.org/10.1007/978-94-007-5497-3

3 General upscaling workflow

In this chapter, we describe a general workflow of upscaling of properties from the core scale to reservoir scale. For a lot of the parameters, the steps in the workflow are very similar. By discussing the steps in a general way, we avoid a lot of repetition. This chapter describes the possibilities and points of attention going from a small scale to a larger scale. However, no parameter specific techniques are described in this chapter. Those are listed in Chapter 4.

In geothermal projects, it is generally out of budget to drill an exploration well. This means that the data that can be used to carry out studies for the SDE+ subsidy and geothermal license applications, are the data that are already available. This usually concerns petrophysical data, seismic data and well test data from hydrocarbon projects or other geothermal projects. In a few locations this includes core (analysis) data from offset wells too. This brings up several challenges:

- The location of the datapoints is generally not at the exact location of interest. The geological framework is needed to be able to translate the data to the project location, this introduces uncertainties.
- The main data source are oil and gas wells. Usually these wells are drilled on the structural highs rather than the structural lows where the geothermal wells are drilled to. This means that the results must be extrapolated to the geothermal target depths with some kind of depth adjustments.
- The data was gathered for a different purpose. It therefore does not necessarily contain all the data that is preferred to do a geothermal study.

The following data sources are generally used in geothermal studies:

- Hydrocarbon and geothermal wells within a few km from the project site, containing the following data:
    - Lithostratigraphy
    - End of well report (EOWR)
    - Logs: for example, Litholog, gamma ray, sonic log, SP
    - Well test data (e.g. production & injection tests, leak off test data)
    - Cuttings
- 2D or 3D seismic data
- Core data (regional), taken in the relevant formation
- Literature

It is important to gather and organize the available data and to understand the geological setting you are working in. On basis of these data, the upscaling workflow can be started as summarized in the 5 steps listed below and visualized in Figure 2.

1. Property selection and measurement on core/cutting
2. Log property calculation
3. Log property calibration
4. Property upscaling
5. Upscaled property calibration

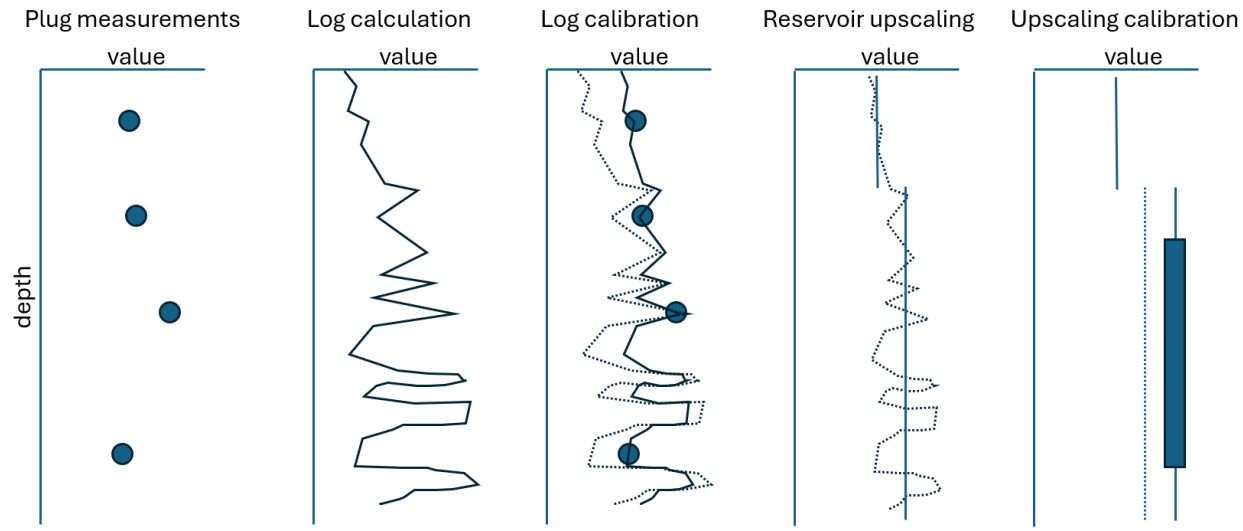


Figure 2: Schematic workflow of upscaling from plug measurements to reservoir scale.

3.1 Project database and general geological description

Before starting upscaling processes, it is advised to create a database with representative offset core -, petrophysical - and, if available, (geothermal) well test data. The data in the database can be based on literature, open data sources such as NLOG, or if available on more region specific data such as core and image logs of (offset) wells in the area. The database helps to identify similar formations/systems if no location specific data is available. It should be noted that using literature or offset data will increase the uncertainty, and that having a good quality location specific dataset is always preferable. The data in this database is used to generate relevant reservoir properties through a workflow that includes an upscaling component. . Please note that the database is not a static database. In the following steps we might discover that we have to add more data, or to label data as “not applicable”.

After building the database, the first step in every project should be the general geological description of the reservoir and seals. This description should contain at least the following:

1. sedimentary setting, stratigraphy, diagenetic & tectonic history
2. rock description
3. structural data

The sedimentary setting gives an understanding of the lateral extent of the reservoir and seal formations. Knowing these helps to make better decisions how to inter- and extrapolate well data. The lateral extent of the formation is important information in the calibration step using well tests. The diagenetic & burial history is helpful in making correct assumptions in the property prediction workflows, and understanding results.

The lithology description of reservoir and seals ideally contains both the composition and the microstructure of the rock. The lithology description is used to determine the flow intervals and the net-to gross (N/G) ratio of the reservoir. This N/G ratio is an important parameter for determining the flow properties and, with that, the geothermal potential.

The structural information include the most important formation boundaries and faults. Faulting Is important for several reasons. It does influence the lateral extent and continuity of layers. The fault location and density are important input parameters for seismic hazard and risk analysis.

TNO has provided a good document on the requirements of the geological description when geothermal projects are applying for SDE+ and RNES.[8] This document contains guidelines on the subjects mentioned above.

3.2 Property selection and measurement

3.2.1 Which property do you want to know?

The first step is to define which property exactly is needed for your calculation. Although this seems very obvious it is sometimes a source of misunderstanding later in the process. To select the exact property, it is important to know in which analysis you want to use the results. For example, if someone needs the porosity, it is important to know if connected porosity or total porosity is needed. The first one is used in flow calculations, but the second is measured when determining porosity from weight and size. Another example is the Young's modulus that is used in the calculations of temperature-induced stress changes. From well logs, the dynamic Young's modulus can be calculated using sonic velocities, but this can be up to three times more than the static Young's modulus measured on rock plugs. It is important to know which one is needed for the calculation you want to perform, which is the static Young's modulus in case of stress changes due to temperature changes.

This works also the other way around. If data are already available from reports or public sources, make sure that you know which property is exactly measured, how that is measured and what are the uncertainty ranges on the measurements, to ensure that the right value is used in the analysis.

3.2.2 Property measurement

As soon as you know which property is exactly required, we can determine the best method to measure this property on core and/or cuttings. To select the most suitable technique, it is important to understand the physics of the measurement. By knowing the physics of the measurement, you can decide if the reported value can be used in your analysis or needs conversion or correction before it can be used.

Since most measurements are done on core plugs, it is important to know if the coring, storing and plug drilling could have had an effect on the property you are measuring. For example, if a shale core is not stored correctly, it might dry, which will strongly change its mechanical and flow properties. This might be a reason not to measure certain properties, since they wouldn't be representative for the in-situ properties of the formation of interest.

Representativeness of measurements

In practice, it is often the case that we have measurements that are not necessarily representative of the entire section of interest. Some parts of cores are really hard to plug like organic matter, thinner than plug-size lithological intervals, and laminated or friable lithologies. As an effect, those

[8] Mijnlieff et al. 2017. Specificaties geologisch onderzoek voor geothermieprojecten – Rapportagevereisten SDE+ en RNES. TNO 2017 R10498. https://www.nlog.nl/sites/default/files/specificaties_geologisch_onderzoek_sde_en_gr_2017_final.pdf

lithologies or lithological intervals are hardly measured and might lead to increased uncertainties in the upscaling. For example, if you only select strong rocks for plugging, then those plugs are not representative for the weaker parts. Or, if impermeable laminae in highly permeable lithologies are not sampled and so measured, permeability results may be too high compared to the overall interval. This might be solved when matching the plug measurements to the well logs as we will see in the next chapter, but this can cause a bias to the stronger/permeable parts.

It is important to document the reasoning why certain plugs are taken of certain parts of the core. For example, was it a plug every 1m, or was it specifically taken from a certain layer? Were well or core logs used to determine the plug location? By documenting the reason, it is possible for others in a later stage to understand if the plugs are representative or not.

Uncertainty in measurements

Although measurements are mostly reported as a single value, it should be understood that every measurement has an uncertainty band, also when it is very small. Depending on the measurement, it can be that repeat measurement on the same plug, or a very nearby plug, will give (slightly) different answers. There may also be a difference from machine to machine or lab to lab used for the same measurements. Also, different measuring techniques for the same parameter will likely give non-identical answers.

Some final resultant property values can be directly calculated from the measurements, while for some other parameters they are estimated using empirical relationships. The fact that those other parameters are estimated and not measured / calculated will add to the uncertainty.

All the uncertainty sources above should be taken into account when working with measured data. Nevertheless, it should be noted that measured data have a much higher reliability than data from literature or offset wells far away, and hence should be used when available.

3.3 Log property calculation and calibration

Plug or core measurements are sparse. Therefore, in most projects well logging data are the primary data source. Well logging data can come from wireline logging or from logging while drilling (LWD). In the latter case, it is advisable to use the downhole memory data instead of the pulsed data, because the memory data will have a higher frequency, less noise, and less missing data than the real-time data.

It should be noted that most logging tools don't measure a petrophysical property directly. The logging tool measurements need to be transformed to the petrophysical property. For example a Neutron porosity tool actually measures the hydrogen atoms in the formation. Then the porosity is calculated assuming the pores are filled with hydrogen atoms in the fluids. However, it will also measure clay-bound hydrogen too which might lead to incorrect porosity values in clay rich layers.

3.3.1 Log property calculations and conversions

Because the log property has to be calculated from the data recorded by the logging tool, it is important to have a basic understanding of the measurement techniques and physics. An experienced petrophysicist will bring this to the project. For standard properties such as density, the transform from the measured scattered gamma rays to density is done by the logging company.

For other, less standard properties such geomechanical or thermal properties, these calculations have to be performed by the petrophysicist or other domain expert. Care has to be taken if service companies provide a calculated log based on standard processing parameters that are not documented. In that case it has to be investigated if the used settings are correct for the specific location. Because it might give erroneous results because there is no location specific calibration performed. An example of such a log is a minimum stress log which purely based on Poisson's ratio. Such a log without calibration is meaningless.

Log conversions using location specific correlations are needed when there is no standard or physical relationship possible. A petrophysicist or other domain expert can provide advice in this respect. For example, to obtain a permeability log, there will be the need to first create a location specific porosity-permeability correlation (poro-perm curve) that can be used to convert a porosity log into a permeability log. This correlation is created from core measurement results that are deemed most applicable to the case and location. How to make these specific conversions will be discussed in Chapter 4.

Inter- and extrapolations

If location specific correlations are made, then these will be more reliable between measured values (interpolation) than outside the measured values (extrapolation). It should also be checked if the correlation can be used outside the measured range, because some curves will become non-physical outside the measured range (see example in Figure 3).

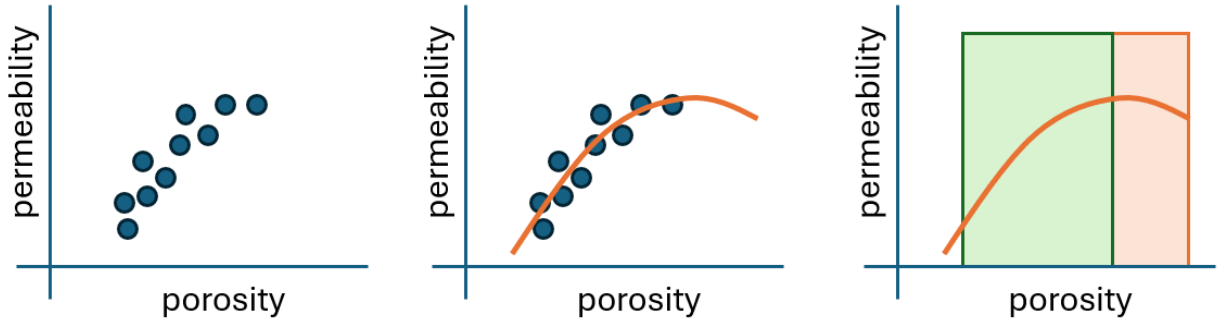


Figure 3: Schematic visualization of poro-perm curve, and danger of using extrapolated values. The left plot shows the measured core porosity and permeability. This data is used to derive a poro-perm curve which fits the data (orange line, plot in the middle). The right plot shows which part of the curve is reliable (green shaded), the red shaded area shows the part which can't be used because it is unphysical: the permeability decreases with increasing porosity which is invalid.

Uncertainty

The more calculations and conversions are done to calculate the log property needed, the larger the uncertainty will be. The uncertainty can be reduced by calibrating the calculated log curve using core or cutting measurements as described in the next section.

3.3.2 Log calibration

Log calibration is important to obtain the most reliable log curve. An appropriately calibrated log will match with (corrected) core plug measurements. The comparison can be performed by plotting the core plug measurements on a well panel, or by deriving the well log values on the plug depths and plot them in a measured vs log value plot (Figure 4). It should be mentioned that we should be

careful to not create circular reasoning by first using core data to obtain a correlation, then to calculate a log with this correlation and then use the same log data again to check the log.

To be able to compare, we need first to make sure that the coring depth is matched with the logging depth. The drilling company and logging company are not using the exact same downhole depth reference. Therefore, it is important to know how much they differ. The difference between the two is the so-called core-log shift. Commonly, the shift is determined by comparing the core gamma ray with the well log gamma ray. The used reference depth to display all data on is commonly the well log depth domain. Care has to be taken if more than one set of logging runs have been performed, because the exact depth may differ between the different runs.

An update of the conversion relationships as discussed above might be necessary if there is a mismatch between the core measurements and the log values. To obtain an update it is important to understand the mismatch. It might also be that the mismatch is (partially) due to the uncertainty in the core measurement and/or log calculation, or related to comparing non-identical parameters (bulk vs. matrix values, ambient measurements vs. measurements at in-situ conditions). If there is still a mismatch after the update, then the mismatch is an indication of the uncertainty in the calculated log values. In this latter case it should be noted that the uncertainty might be even larger than the mismatch.

When improving the conversion relationship it should be understood that a larger amount of (plug) measurements, and therefore calibration points, will lead to a more robust relationship, then using only a few points as illustrated in Figure 4. Relationships derived from a small amount of calibration points will lead to a larger uncertainty in the calculated properties.

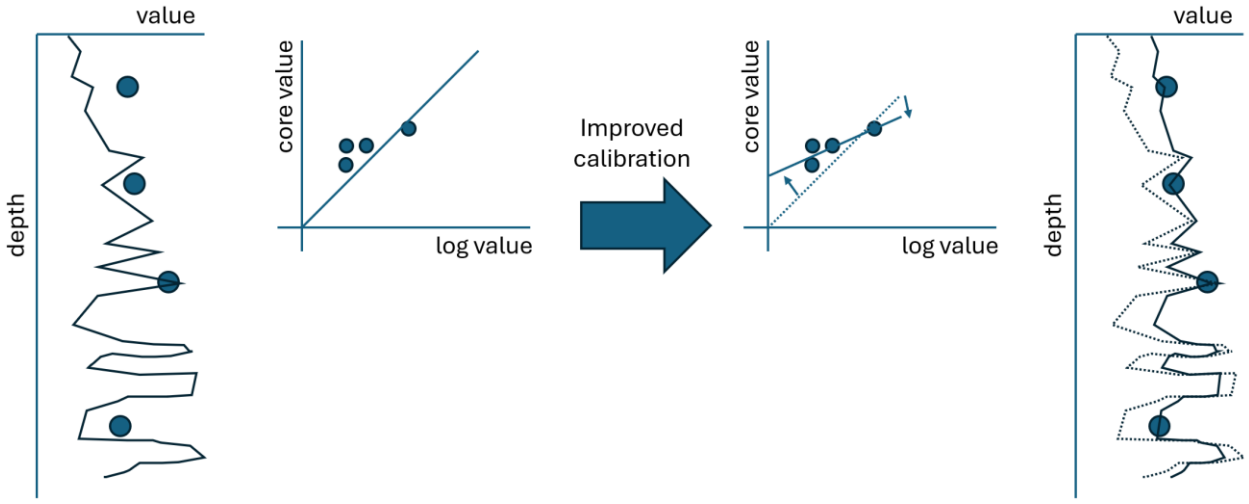


Figure 4: The left panel shows the log data with core plug measurements (core shift applied). It can be seen that one point is on the log curve, but three plug measurements are not matching the log values. In the left calibration plot the core plug measurements are plotted versus the log values at the corresponding depth. It shows that the lower log values underestimate the core measurements. With an updated calibration which increased the lower log values a much better match is obtained (right 2 panels).

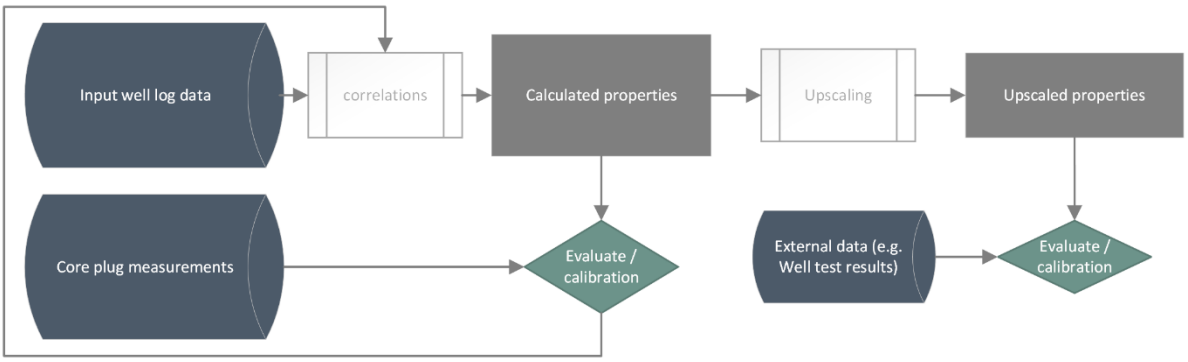


Figure 5: The general workflow for property prediction and upscaling as described in this report. Note that data correlations and data upscaling have to be done within a geological framework.

3.4 Property upscaling to reservoir scale

Many commonly used tools in geothermal exploration and exploitation in the Netherlands such as DoubletCalc[9] and SRIMA[10] are based on relatively simple reservoir, fault geometries and calculations compared to the reservoir models used in the oil and gas industry. The advantage of these simpler calculations is that they will lead to faster calculation times, allowing for stochastic calculations to quantify the uncertainty. This is important because for many projects the data availability is relatively limited, which automatically makes it hard to estimate a representative value for a reservoir (interval). Therefore, an uncertainty analysis helps to quantify the associated uncertainty. To be able to use these tools, we have to describe the whole reservoir or whole seal with only one single property value, even if we have higher resolution data. To be able to do this, we have to upscale from the wellbore to the reservoir scale.

Upscaling is done with a model. As with all models, we have to consider that the best upscaling method might be dependent on future usage of the upscaled parameter. This means that there is no "one size fits all" method for upscaling. As an effect of this, the user must know, before starting the upscaling process, how the parameter will be used, so he/she can decide how representative the upscaled value is for the formation with that usage.

It can be necessary to use different upscaling methods for different parameters. If these parameters are correlated to each other, it can mean that the consistency gets lost in the process. In other words: if some input parameters are correlated on a smaller scale, they might not correlate as well anymore when upscaled. Depending on the usage of these parameters this might be a reason to select the upscaling method differently to keep the consistency, and with that the correlation.

[9] Tools | NLOG
[10] SDRA Geothermie & Integriteit afdichtend pakket | NLOG

3.4.1 Upscaling methods

There are many different models for upscaling, ranging from simple to complicated. The selection of the most adequate model is depending on the parameter you want to upscale, the available input data, and for which analysis or tool you want to use the parameter.

The more simple techniques produce a single, non-directional value for the whole formation. The most commonly used upscaling techniques in this respect are the arithmetic, harmonic and geometric averaging (explained below). In addition, there are some domain-specific techniques, such as Swanson's mean in upscaling permeability and Hill's averaging for elastic moduli.

The more complicated upscaling techniques result in an effective medium. This means that upscaling of a layered formation results in an equivalent homogeneous medium that has the same behavior as the layered medium. This is only possible if the upscaled value is not expressed in a single value, but expressed as a tensor. There are only limited analytical methods for this kind of upscaling, and is only valid for specific geometries (e.g. perfect horizontal layering, where properties are perfect oriented to this layering). Therefore, most of this kind of upscaling is done numerically to allow for more diverse geometries and for differences in material properties.

Arithmetic mean

The arithmetic mean (AM) is commonly known as "the average". It is the sum of all values divided by the amount of values.

$$AM = \frac{x_1 + x_2 + \cdots + x_n}{n}$$

The arithmetic mean is sensitive to large outliers. If one of the numbers is (very) large in comparison to the other numbers, this number will have a large effect on the calculated mean. This shows the importance of good QA/QC of the data and removing unrealistic high values (e.g. caused by measurement errors or bad hole conditions) before averaging to avoid unrealistic results. With respect to upscaling, this averaging technique is used when the direction of interest (flow or compression) is parallel to the layering.

Harmonic mean

The harmonic mean (HM) is more representative if the direction of interest (flow or compression) is perpendicular to the layering. The harmonic mean is mathematically expressed as follows:

$$HM = \frac{n}{\frac{1}{x_1} + \frac{1}{x_2} + \cdots + \frac{1}{x_n}}$$

The harmonic mean is less sensitive for large outliers and puts more weight on the smaller values.

Geometric mean

The geometric mean (GM) is used when there is no significant anisotropy direction in the formation of interest. The geometric mean is mathematically expressed as follows:

$$GM = \sqrt[n]{x_1 \times x_2 \times \ldots \times x_n}$$

The geometric mean will always be between the arithmetic and harmonic mean, except when all input values are the same, because then all three the means will give the same value.

Numerical upscaling

As described above, there are only limited analytical methods to obtain an effective medium with a tensorial representation of the properties. Therefore, in most cases where an effective medium is needed the upscaling is done numerically. In this technique, the to be upscaled volume is numerically subjected to certain boundary conditions, and the result is calculated back to a homogeneous property per direction. An example of simple numerical upscaling is the following: to get the permeability of a rectangular volume in 3 directions, the volume is numerically subjected to a pressure gradient in one direction (e.g. top-down), and it is calculated how much flow is expected. Then this flow is calculated back to a single permeability value for the vertical flow. This is then repeated for the other two directions to get the full permeability tensor.

3.5 Upscaled property validation and calibration

The last step in the upscaling workflow is to check if the upscaled values match reality, such as measured in well tests. This is done by checking if using the upscaled property in a model will produce results comparable with measured data from, for example, a well test. In other words: the validation is done by comparing expected outcome with real outcome. If necessary adjustments are made in such a way that the expected and the real outcome match.

The calibration in case of a misfit is not as straightforward as it looks at first sight. The upscaled value is used in a model which calculates the expected outcome. This model outcome is compared with a measured value from for example a well test. If the model doesn't fit, then some input values of the model might have to be changed to get a better fit. However, that model will contain many other parameters besides the upscaled value we want to calibrate. These other parameters are also based on estimates and are not necessarily more correct than the parameter we want to calibrate. Finaly, we should also be aware that the model is based on certain assumptions and boundary conditions. For example, in a well test, it is assumed that the reservoir parameters are horizontally homogeneous and the inflow is radial. However, if the inflow is not radial due to reservoir heterogeneities then the calculated results will be not reflecting the actual situation. This shows the importance of geological knowledge of the reservoir (and cap rock). This knowledge may be an important guide for making decisions. Similar looking data which results from completely different burial histories might need different upscaling techniques.

So if there is a poor fit then it might be that the upscaling was wrong, but it could also be that one of the other parameters were wrongly estimated and need changing, or that the used model doesn't match the actual well test. It is often hard to know which parameter needs adjusting. As a result, the whole process is often only a validation process, but with enough data is can be a real calibration process.

Care has to be taken that after the adjustments the result might be comparable, but it could be right for the wrong reasons because the system is not very constrained and will have more than one combination of input parameters matching the measurement. Therefore, if possible, always try to have more than one test run and change one of the parameters of the test (e.g. pressure) to make sure you are testing and calibrating the right parameters.

3.6 Reservoir to project location

In many cases the user wants to know the properties on a new project location that might be a (significant) distance away from the wells that were used to obtain the upscaled properties. The best method to obtain the project location values is depending on many factors such as the distance to the original data, lateral continuity of the formations, structural geological setting etc.

Methods to derive the properties at a new location include (but are not limited to): create porosity maps using maximum burial depth maps to obtain values at the new project location, analyzing for trends against other (continuous) datasets, using structural data to identify structural domains which are assumed to have related properties or a combination of multiple of these methods. With enough data availability it might be worthwhile to go for grid based geostatistics, which may be supported by 3D seismic attributes. In any case, a thorough conceptual geological model should be at the basis of any property distribution (and resultant property prediction at a new location). Since the best method is very case specific, we won't discuss this step in this guideline.

If the methods above are used, then it should be noted that the techniques might have different effects on the properties which can lead to loss of consistency within the dataset. It is obvious that, given a certain geological setting, the further the new location is away from the original data, the higher the uncertainty in the values at the new location.

4 Upscaling reservoir & seal properties

In the Netherlands several studies have to be carried out before a geothermal project can be drilled. The three important studies are the SDE++ application, the SHRA study (Seismic hazard and risk assessment) and the seal integrity analyses (Tensile failure Assessment of the Seal, TAS). In this chapter, we describe the parameter-specific upscaling steps for the most important parameters for the models used in these studies (DoubletCalc and SRIMA). This upscaling guide is not tailored to these models, but we will refer to these models when discussing the input parameters.

In Table 1 all input parameters that are needed for these models are listed. It should be noted that some input parameters are calculated using other or combinations of other parameters. These parameters will also be described in this chapter.

Table 1 also gives the impact of these parameters on the thermal power, seismic risk, caprock integrity and its typical uncertainty. This table therefore gives an indication on the importance of getting accurate upscaled results for each parameter, such that a good estimate can be made on geothermal power and operational bounds. We can divide the parameters in in 4 categories:

1. General formation properties
2. Flow properties
3. Geomechanical properties
4. Thermal properties

Table 1: The reservoir parameters relevant for the SDE++ and the SHRA, and the method that is generally used. In the column "Chapter" a reference to the description of the parameter is given.

Parameter	Chapter	Needed for	Impact on thermal power	Impact on estimating seismic risk	Impact on estimating caprock integrity	Typical uncertainty (pre-drill)
General formation properties						
Depth [mTVD]	4.1.1	SDE++/SHRA	High	Low	Low	Low
Thickness (gross) [m]	4.1.1	SDE++/SHRA	High	Low	Low	Low
Net/Gross [-]	4.1.1	SDE++/SHRA	High	Low	Low	Low/Med
Salinity [ppm]	4.1.2	SDE++/SHRA	Med	Low	Low	Low/Med
Porosity [-]	4.1.3	SDE++/SHRA	Low	Low	Low	Low/Med
Flow properties						
Permeability [mD]	4.2.1	SDE++/SHRA	High	Low	Med	Med/High
Geomechanical properties						
Compressibility (rock) [1/Pa]	4.3.1	SHRA	Low	Low	Low	Med/High
Young's modulus [GPa]	4.3.1	SHRA	Low	High	High	Med/High
Poisson ratio [-]	4.3.1	SHRA	Low	Med	Med	Med
Biot coefficient [-]	4.3.2	SHRA	Low	Low	Med	Med
Thermal exp. coeff. [1/K]	4.3.3	SHRA	Low	High	High	High
Friction coefficient [-]	4.3.4	SHRA	Low	High	High	Low/Med
Unconf. compr. Strength (UCS) [MPa]	4.3.4	SHRA	Low	Low	Low	Med/High
Stress conditions						
Vertical Stress (S_V) [MPa]	4.5.2	SHRA	Low	Low	Low	Low

Min. Hor. Stress (Sh) [MPa]	4.5.3	SHRA	Low	High	High	Med/High
Direction stress field [°]	4.5.4	SHRA	Low	Med	Low	Med/High
Max. Hor. Stress (SH) [MPa]	4.5.4	SHRA	Low	Med	Low	High
Thermal properties						
Heat capacity (rock) [J/kg/K]	4.4.1	SHRA	Low	Low	Low	Low/Med
Thermal conductivity (rock) [W/(m k)]	4.4.2	SHRA	Low	Low	High	Med
Reservoir temperature [°C]	4.5.5	SDE++/SHRA	High	Low	Low	Low

In this chapter, the high-level parameter specific workflows are given. For detailed upscaling workflow an appendix per parameter has been added at the end of this report.

4.1 General formation properties

In this chapter we describe the following general formation properties:

1. Reservoir and seal properties
2. Density
3. Porosity

4.1.1 Reservoir & seal description

Rock description

An important input for all workflows is the lithology description of reservoir and seals. This description ideally contains both the composition and the microstructure of the rock. The description can be obtained from cuttings, cores and supported by logs. It is worthwhile to have good mudlogging and cutting sampling because it is valuable information that is gathered on every well drilled. The cuttings and cavings can also be used to analyze for mineralogy and measurements of certain rock properties.

The combination of logging data and lithology description is used to determine the flow intervals and the net-to gross (N/G) ratio of the reservoir. This N/G ratio is an important parameter for determining the amount of permeable sands which can contribute to flow within a reservoir.

Care should be taken when calculating the geothermal potential that the (averaged) porosity/permeability values used should match the N/G definition. For example, if low permeable sands are also defined as net, then the average permeability will be lower than a case where only the high permeable sands are defined as net.

Further, the rock and fluid composition is important in several upscaling workflows. For example, the mineralogy can be used to estimate the thermal expansion coefficient if no core material is available for measurements. The rock composition can be determined on core, but if no core is available, then cuttings and cavings can be a very valuable to determine the rock composition. In certain cases a mineralogy log can be constructed from a geochemical logging tool (e.g. Lithoscanner from Schlumberger or FLeX from Baker Hughes) which combines several measurements such as (but not limited to): (spectral) gamma ray, deep & shallow resistivity, neutron density and others. The microstructure, such grain shapes, matrix, cement etc., is an input to certain workflows for flow predictions.

More detailed description on rock composition measurements can be found in Appendix 1: Rock Composition.

Sedimentary setting, diagenetic & tectonic history

Another important aspect of the geological description is the sedimentary and diagenetic & tectonic / burial history. If we understand the sedimentary setting, then we have a better understanding of the lateral extent of the reservoir and seal formations. Knowing these helps to make better decisions how to inter- and extrapolate well data in our area. The lateral extent of the formation is important information in the calibration step using well tests.

The diagenetic and burial history is helpful in making correct assumptions in the property prediction workflows, and understanding results. For example, if an area has been subjected to an uplift phase at some point in its history, then current depth is not a good predictor for porosity, and we need a burial anomaly map when working with depth dependent parameters such as porosity.

Structural information

The structural information of the subsurface should be gathered for every project. This should include as a minimum the most important formation boundaries and faults. Faulting is important for several reasons. It does influence the lateral extent and continuity of layers. Lateral extent and continuity are important parameters for property inter- and extrapolation. Layer discontinuity and faults that act as a baffle for flow will influence the interpretation of well test. The fault location and density are also important input parameters for seismic hazard and risk analysis.

The structural information should preferably be gathered from good quality 3D seismic data specifically processed to determine the structure. Using 2D instead of 3D data will increase the uncertainty. Using seismic cubes which are processed for another goal than structural interpretation might lead to increased uncertainty. A good data set includes a time-depth conversion calibration based on well data. The structural uncertainty will increase in the absence of a good time-depth calibration.

4.1.2 Density

Density is an important input parameter in several other workflows such as porosity determination, thermal diffusivity calculations and for vertical stress calculations in geomechanical applications. The three most important parameters are bulk density (ρ_b), grain (or matrix) density (ρ_{gr}) and fluid density (ρ_{fl}).

Measurement

Grain and bulk densities can be measured in a lab on core plugs or cuttings. For measurements of the bulk density it is important to make sure that the original saturation of pore fluids is still present. If that is not the case, then the measured value is not a good representation of the in-situ bulk density and it is better to use other methods to determine the bulk density.

With an assumed grain density and measured porosity, it is possible to calculate a dry density. Using the fluid density and porosity this dry density can be converted into a bulk density. It should be noted that to assume a representative grain density it is useful to know the mineralogy of the rock.

Dry density (no pore fluids):

$$\rho_{dry} = (1 - \phi)\rho_g$$

Bulk density (with pore fluids):

$$\rho_{bulk} = (1 - \phi)\rho_g + \phi\rho_f$$

where:

- ρg = grain density
- ρf = fluid density
- ϕ = porosity

Fluid density can be measured in the lab from fluid samples taken from the well with a formation testing tool, or using the test water from a well test which has flown long enough to be sure that the sampled water is actual formation water. The fluid density can also be calculated using reported salinity using equation published Batzle and Wang (1992)[11] (see appendix 2). These equations are also build in DoubletCalc and probably in SRIMA.

Log property calculation and calibration

Bulk density is most commonly measured with a density wireline tool in a well. The density is based on the reduction in gamma ray flux between a radioactive source and a detector due to Compton scattering. The service companies will do all the necessary calculations and corrections (e.g. mud infiltration) to obtain the bulk density. The measured values will be influenced by hole quality (e.g. break-outs) and therefore the results need to be quality checked versus other tools such caliper or image logs. If it is not possible to use a wire line tool with an active source, then the density can be estimated using sonic tool measurements and published V_p to ρ_b relationships.

Fluid density logs can be derived from the fluid pressure gradient in the well bore after well testing with only formation fluids in the well. If this data is not available, then the fluid density can be estimated by using the (expected) salinity.

Upscaling

A good quality bulk density log (with no unrealistic outliers) can be upscaled to a larger volume (e.g. a single value for the whole formation) by using the arithmetic mean.

Formation fluid density is generally assumed to be constant through the reservoir. In the case of very thick reservoir with an expected fluid density gradient, the upscaled fluid density can be obtained by calculating the arithmetic mean.

[11] Batzle, M., & Wang, Z. (1992). Seismic properties of pore fluids. Geophysics, Vol.57, 1396-1408.

Upscaling calibration

It is not possible to calibrate the upscaled bulk density logs since there is no known test to directly determine the average density of a whole formation. More detailed description on density measurements and upscaling can be found in Appendix 3: Rock Density

4.1.3 Porosity

Porosity can be defined as the total pore volume per unit volume of rock, or the total volume of space within a specific rock than can be filled with a fluid. This includes isolated pores (which don't contribute to flow) and pore volume that is occupied by water that is adsorbed to certain grains, the so-called clay-bound water. Porosity is unitless and is usually given as a decimal between 0 and 1.0, or as a percentage, between 0 and 100%.

Porosity is not a direct input value in the modelling tool DoubletCalc but it is an important parameter in several upscaling workflows, especially in estimating the formation permeability that is a very important input in DoubletCalc. Total porosity of the seal is an input value in SRIMA.

Types of porosity: total and effective porosity

There are two main types of porosity: total and effective porosity. Total porosity is the amount of pore space in a volume, which can be connected to each other, or disconnected (also called isolated pores). Effective porosity is the pore space which contributes to flow. Those two types are two separate things and might be very different numbers, especially in shaly environments. Figure 6 is an overview of the different types of porosity (several schemes exist) and which measurement methods measure what porosity.

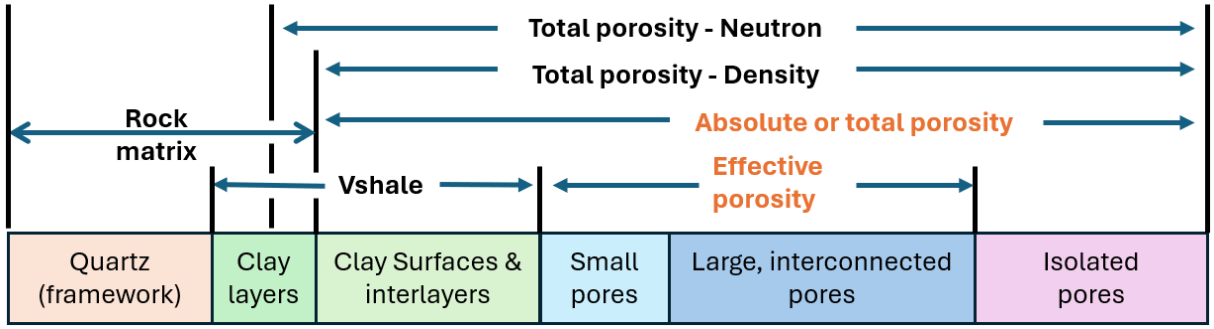


Figure 6: Scheme of different porosity types and measurement methods (after Eslinger and Pevear, 1988[12])

Measurement

Porosity measurements from core material are usually measurements on core plugs (small pieces of core with a cylindrical shape, approximately 1 inch in diameter), sampled from a whole core. It is important that the porosity is measured on intact core (without fractures) to avoid measuring the fracture porosity as well, which would lead to an erroneously high porosity. This means that porosity measurements on side wall cores are possible after a good quality check of the side wall cores. The quality check is important because the method how side wall cores are taken leads to a higher risk of induced fractures.

[12] Eslinger E. & Pevear D. 1988. Clay Minerals for Petroleum Geologists and Engineers

Porosity measurements are usually done in the laboratory under ambient (surface) conditions. However, the in-situ rock has a different pressure regime, which should be accounted for. For a guide on calibrating porosity measurements back to in-situ situations see appendix 4 were the method proposed by Evans et al., (1994) is explained.

Log property calculation and calibration

Porosity cannot be measured directly by well logs, it can however be calculated from certain logs. The main logs that are used for porosity evaluation are neutron porosity (NPHI) and density (RHOB) in combination with a gamma-ray log and caliper log. The gamma ray log is used to estimate shale and clay content to be able to correct for clay-bound water, and the caliper log is used to correct for hole quality. From NMR (nuclear magnetic resonance) logs porosity can also be calculated. In absence of those logs one can also use sonic logs together with empirical relationships, but that will increase the uncertainty of the final porosity log. An experienced petrophysicst can evaluate these logs in a proper formation evaluation exercise.

As described above, porosity log measurements are indirect measurements and these can be affected by borehole conditions and the tool-settings. Care is given by the log-providing company that the tool-settings are correct, but QC by the operator ('witnessing') might be advisable. For further desk-top calibration the petrophysicst needs to know the borehole conditions: pressure, temperature, formation fluid composition (for example salinity) and borehole fluid compensation, as well as the size of the borehole (caliper). Despite all these calibration steps a proper porosity calibration can only be done by matching core-plug porosities measured in a lab to the logs. Care should be given to a couple of things such as type of laboratory measurement and in-situ corrections.

Upscaling

The porosity log can be upscaled to a single value for a formation using the arithmetic mean. This would lead to a similar total pore volume for the log as for the "single parameter" reservoir. However, it is very likely the porosity distribution will be bi-modal with low porosities for the clay rich formations, and higher porosities for the sandstones formations. Therefore it is useful to first apply the N/G cut-offs and then define the average porosity for each lithology interval. In the case of flow modelling, this would be determining the average net porosity for the flow and non-flow intervals.

Upscaling calibration

Porosity is one of the inputs in a well test evaluation. The well test workflows are not tailored to calibrate the upscaled porosity, but they might put constraints on the porosity range, which can be used as a calibration for the upscaled porosity. More detailed description on porosity measurements and upscaling can be found in Appendix 4: Porosity.

4.2 Flow Properties

4.2.1 Permeability

Permeability can be defined as a measure of the ability of a rock to transmit fluids, in other words, the more permeable a rock or reservoir is, the easier it is to transmit a fluid through it. Permeability refers to how interconnected the individual pore spaces are to another. These pore spaces were defined in the porosity property described in Section 4.1.3.

The traditional unit for permeability when referring to reservoir evaluation (e.g. for geothermal or hydrocarbons) is millidarcy (mD) or Darcy (D), which is a practical unit based on the SI (Système International) unit square meter (m^2). For 1 Darcy this means the equivalent to the passage of one cubic centimeter of fluid (having a viscosity of one centipoise) per second through a sample one square centimeter in cross-sectional area under a pressure of one atmosphere per centimeter of thickness.

Types of permeability

Absolute permeability is the measure of the permeability when a single fluid or phase is present in the rock. This means that the fluid in the rock when the measurement is taken is for example 100% water or 100% gas. Effective permeability becomes relevant when other immiscible fluids are present; it is a measure of the permeability of a porous medium for one particular fluid phase when more than one fluid is present in the rock . This depends on the geometry of the pores, rock wetting characteristics and fluid saturation. Relative permeability is the ratio of the effective permeability of a fluid at a given saturation to the absolute permeability of that fluid at 100% saturation (absolute permeability).

In geothermal reservoir evaluation we usually only refer to absolute permeability as we assume the reservoir is completely filled with brine. Relative permeability effects could possibly play a role when free gas or oil are present in the geothermal reservoir or when drilling mud has invaded the reservoir.

Measurement

Permeability is commonly measured on core plugs, ideally on the same plugs as the porosity measurements were done. In a standard test there is a pressure applied on one side of the plug, and the flow through the sample is measured. Commonly helium gas is used as de flowing medium. Using Darcy's law allows for calculation of the permeability. There are also measurement techniques which work with pressure fluctuations or attenuations, but these are especially designed for tests on very low permeable rocks such as shale or salt samples.

The permeability should be similar for different flowing media as long the saturation is 100% of that medium. However, there will be a difference when using gas instead of fluid as the flowing medium, the so-called Klingenberg effect. To be able to compare the results we need to correct for this.

If enough core material is available, it is worthwhile to core the plugs parallel to the internal layering and perpendicular. In that way the vertical to horizontal permeability ratio (K_v/K_h) can be estimated.

Log property calculation and calibration

Core data analysis: Analyze the core plug measurements in order to acquire

- a relationship between the effective porosity (phie) and permeability for the reservoir (poro-perm curve).
- a relationship between vertical and horizontal permeability (K_v/k_h).

Petrophysical analysis: Use the V_{clay} and porosity logs described in chapter 4.1.3 and the core data relationships in order to calculate K_h and K_v from porosity.

Check the results against the available core data and proceed when the results are overlapping. If the results don't overlap sufficient, then investigate the source of mismatch and update where necessary (e.g. poro-perm curve) as visualized in Figure 4.

Upscaling

The calculated reservoir properties for each interval: porosity, permeability, N/G and net thickness are used to upscale to reservoir scale. It should be noted that it is advised to never use upscaled porosity to calculate the upscaled permeability using a poro-perm curve derived from core data, but always go through a permeability log before upscaling.

There are different methods to upscale the permeability to a reservoir scale. Below the most common ones.

Arithmetic average

As a general rule Arithmetic averaging is used when flow is parallel to the main permeability layering. For horizontal permeability this can thus be used for most sedimentary rocks due to the horizontal bedding and general laminar layering. If permeability has a log linear relationship with porosity at log scale, the upscaled values will lie slightly above this relationship, as the large values have larger impact on flow as the low permeability values.

Harmonic average

The harmonic average is more representative when flow is perpendicular to the main permeability layering. In most cases this is thus used to upscale vertical permeability. For horizontal permeability the harmonic average is hardly ever used, but may be applicable in very steep dipping layers or fractured systems. If permeability has a log linear relationship with porosity at log scale, the upscaled values will lie slightly below this line, as the low permeability values control the flowrates.

Geometric Average

The geometric average is used when there is no apparent preference for vertical or horizontal flow, the rock has no significant anisotropy for flow. This is often used in carbonates, but could also be true in well sorted sandstones, with hardly any vertical baffles. Also fractured systems might have these characteristics. If permeability has a log linear relationship with porosity at log scale, the upscaled values will lie approximately on this line, as this method will try to retain both high and low values

Swanson mean

The P10, P50 and P90 of the permeability distribution is used to calculate the Swanson mean.

$$\overline{perm} = 0.3 \times P_{10} + 0.4 \times P_{50} + 0.3 \times P_{90}$$

This only works well if the permeability distribution is normal. Since only the P10, P50 and P90 values are used in this calculation, it will filter out the very low and high outliers which are below the P10 and above the P90.

k_v/k_h

The ratio between the vertical and the horizontal permeability can be estimated from dedicated core plug measurements. However, these measurements don't capture the internal layering of a formation. If the logs show a profound presence of variations in permeability between the layers then another method has to be chosen. For example k_v/k_h could be estimated using the results of

harmonic averaging and arithmetic averaging since those match with flow perpendicular and parallel to the layering (see above). In the case the data doesn't allow to analyze the k_v/k_h then commonly a value between 0.1 and 0.5 is chosen. Several studies[13] show a variation in the k_v/k_h between these values in consolidated sandstone with strata.

Upscaling calibration

The results of a well test are used to calibrate the upscaled permeability. The well test data is commonly interpreted with commercial flow engineering software (e.g. Kappa). One of the standard results is the bulk transmissivity (K_h * thickness) of the reservoir interval. This value can be compared with the calculated upscaled permeability * reservoir height * N/G. When the results are overlapping, then the upscaled permeability is consistent with the well test results. If the results don't compare then either the upscale workflow has to be performed again with updated parameters, or the well test interpretation has to be revised based on the lessons learned from the discrepancies.

A search through available well test data of 24 geothermal locations shows unfortunately that there are only a limited amount of systems which have enough data to do a solid well test evaluation. From those systems with enough data it can be concluded that not all well tests allow for an accurate and reliable interpretation of the skin and permeability, because of the wellbore storage effects. Wellbore storage is a critical factor in well test interpretation. It represents the sum of all wellbore physics and significantly influences pressure measurements, especially during the early-time periods of a flow- or shut-in test. Wellbore storage can lead to erroneous estimates of reservoir properties such as permeability and skin factor. The only way to mitigate the effects of wellbore storage, is to include a downhole shut-in device in every well test. Unlike drawdown tests, interference tests are less affected by wellbore storage in the offset well. This is because the offset well is typically not producing or injecting, and the pressure changes are primarily driven by the reservoir and flow between the wells. A more detailed explanation on the effect of wellbore storage and its effect on the well tests can be found in Bruijnen (2025)[14].

A detailed description the workflow for permeability upscaling is given in Appendix 5: Permeability.

[13] Meyer, 1989; Shedid, 2019; Hesthammer & Fossen, 2001; Al-Dujaili et al., 2021; Lucier & Zoback, 2008

[14] P. M. Bruijnen (2025); Numerical and analytical modelling of wellbore storage effects in low-enthalpy geothermal well tests. Geoenergy, Volume 3, Issue 1, 2025. https://doi.org/10.1144/geoenergy2024-020 (OpenAccess)

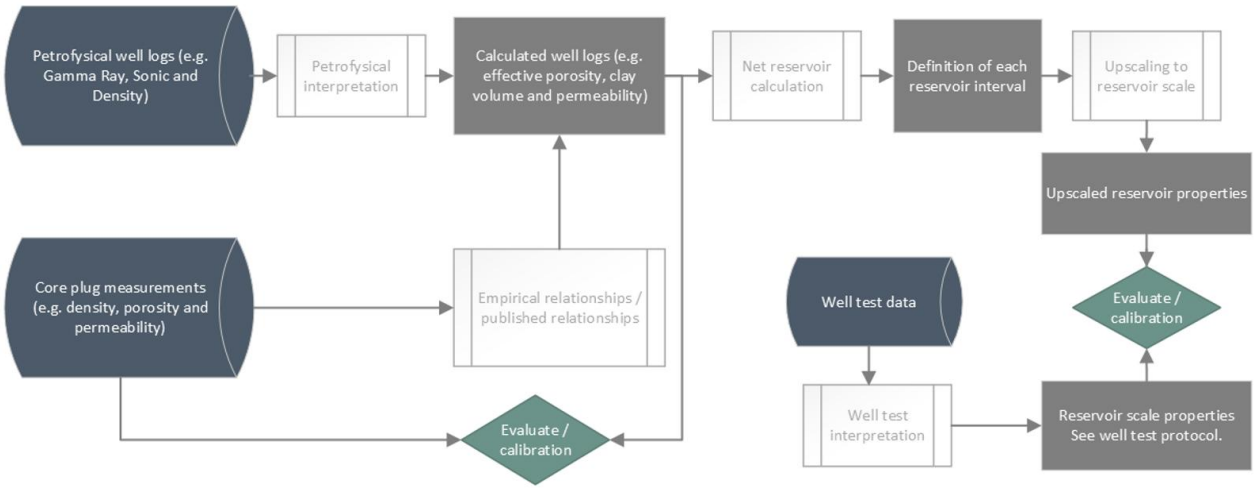


Figure 7: Workflow for upscaling the flow properties given a complete dataset

4.3 Mechanical properties

The next category to describe are the mechanical properties of the formations. The mechanical properties are important for the modelling of the cap rock integrity and the seismic risk analysis. Both analyses can, for example, be done with the freely available SRIMA tool[15]. Below are the six parameters listed we will discuss in this guideline.

1. Elastic parameters:
    1. Young's modulus
    2. Poisson's ratio
    3. Rock compressibility
4. Biot constant
5. Linear thermal expansion
6. Unconfined Compressive Strength (UCS)

Not all parameters above have the same influence on the outcome of the seismic hazard and cap rock integrity analyses. Several projects have investigated the sensitivity on the various input parameters. In this guideline we refer to both the WarmingUp[16] project and the Kennisprogramma Effecten Mijnbouw study 15 (KEM15)[17]. Both studies investigated the effect of the uncertainties on the outcome. Both studies concluded that the Young's modulus and thermal expansion coefficient are important parameters in the seismic risk analysis (see Figure 8).

[15] https://www.nlog.nl/sdra-geothermie-integriteit-afdichtend-pakket
[16] warmingup4b1_report_r1_quantification_of_induced_seismicity_potential_of_geothermal_operations.pdf
[17] https://kemprogramma.nl/blog/view/5a3ab959-6f72-4e34-9ba7-9af80a7d8be0/kem-15-seismic-risk-due-to-cooling-effects-in-geothermal-systems-finished

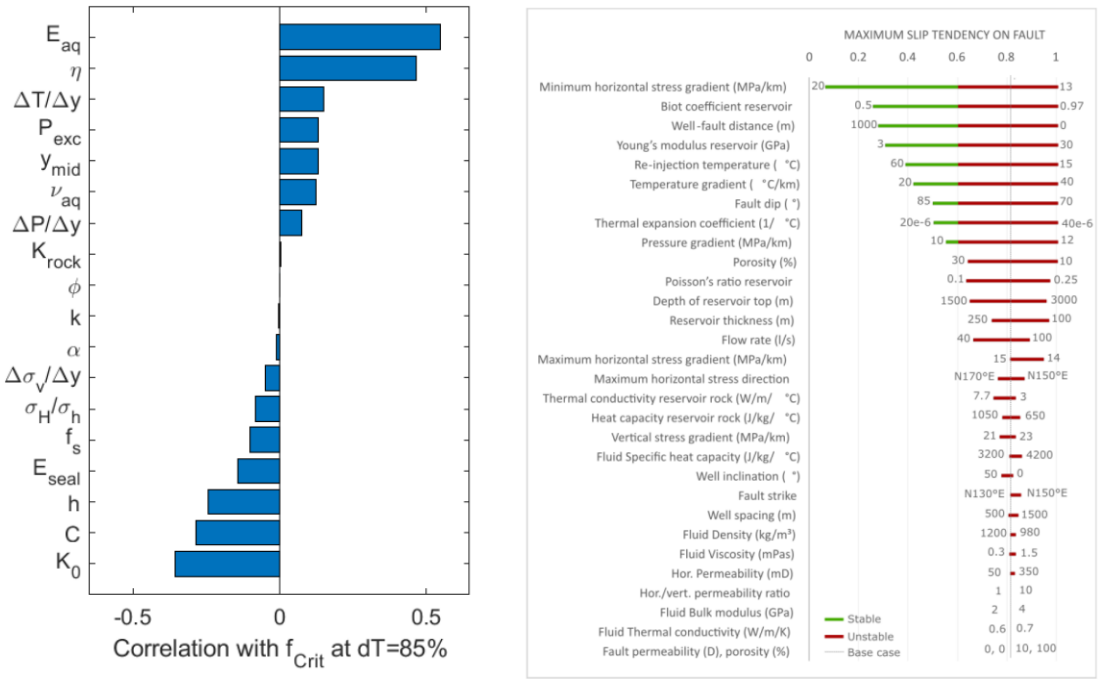


Figure 8: left: figure 3.11 of the WarmingUp project showing that Young's modulus (E) and thermal expansion coefficient (η) have a large effect on fault stability. Right: figure 5.1 of KEM15 shows also that Young's modulus and thermal expansion coefficient belong to the most important rock mechanical properties w.r.t. fault reactivation.

The importance of Young's modulus and thermal expansion coefficient on stress changes due to cold water injection can be explained as follows:

- The cold water injection cools the rock formation around the injector.
- The rock wants to "shrink" due to the cooling.
- The amount of shrinkage is depending on the thermal expansion coefficient.
- The rock can't shrink because it is connected to the surrounding formations, as an effect it will stay more or less the same volume, but with a changed stress state.
- The amount of stress change instead of shrinkage is depending on the Young's modulus.

The theoretical amount of horizontal stress change ($\Delta\sigma_h$) per temperature change (ΔT) is described by the Young's modulus (E), Thermal expansion coefficient (β) and Poisson's ratio (ν) in the following way:

$$\frac{\Delta\sigma_h}{\Delta T} = \frac{E}{1-\nu}\beta$$

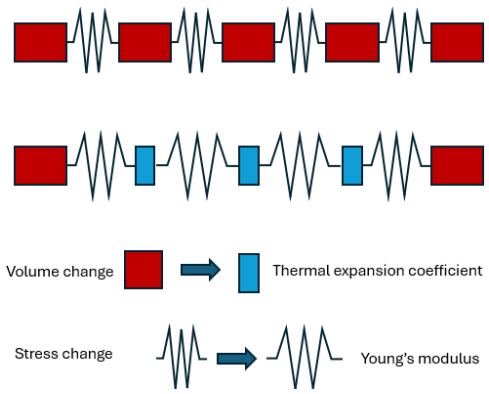


Figure 9: schematic explanation how cooling leads to stress reduction. The red and blue boxes are visualizing the volume reduction due to cooling. The springs visualize the stress reduction. In a rock formation these two processing are happening in the same volume.

It should be remembered that this equation is the theoretical change in stress due to temperature change. In reality the stress change can be more complicated and also dependent on stress arching, shape of the layers, the volume of cooled rock etc.

4.3.1 Linear Elasticity

For determining elastic parameters one should be aware that in ~~a~~ homogeneous, isotropic material it takes only two elastic moduli to describe the material behavior fully. In the table below the most common transforms from one to the other moduli are listed.

Table 2: Relationships among elastic moduli in an isotropic material. K = Bulk modulus, E = Young's modulus, ν = Poisson's ratio, G = Shear modulus.

	K	E	ν	G	M
G, ν	$G\frac{2(1+\nu)}{3(1-2\nu)}$	$2G(1+\nu)$			$G\frac{2-2\nu}{1-2\nu}$
E, ν	$\frac{E}{3(1-2\nu)}$			$\frac{E}{2+2\nu}$	$\frac{E(1-\nu)}{(1+\nu)(1-2\nu)}$
K, ν		$3K(1-2\nu)$		$3K\frac{1-2\nu}{2+2\nu}$	$3K\frac{1-\nu}{1+\nu}$
K, G		$\frac{9KG}{G+3K}$	$\frac{3K-2G}{2(3K+G)}$		$K+4\frac{G}{3}$
E, G	$\frac{EG}{3(3G-E)}$		$\frac{E}{2G}-1$		$G\frac{4G-E}{3G-E}$
K, E			$\frac{3K-E}{6K}$	$\frac{3KE}{9K-E}$	$3K\frac{3K+E}{9K-E}$

Young's Modulus (E)

As described above the Young's modulus is together with thermal expansion coefficient the most important parameter to determine stress change per temperature change. This makes the Young's modulus a very important reservoir parameter in seismic risk assessment, and a very important seal parameter for cap rock integrity assessment.

Young's modulus (E) quantifies the relationship between compressive stress (σ) and axial strain (ε_{ax}) in the linear elastic region of a material $E = \frac{\sigma}{\varepsilon_{ax}}$. The SI unit of the Young's modulus is Pa, and is for rocks normally expressed in GPa.

When working with Young's modulus one should distinguish between the static Young's modulus (E_{stat}), which represents the stiffness at slower, drained measurement conditions and the dynamic Young's modulus (E_{dyn}), which represents the stiffness at faster, undrained, conditions. E_{stat} is normally lower than E_{dyn}.

Measurement

E_{stat} and E_{dyn} both can be measured in the lab on core plugs. The measurement of E_{stat} is commonly done in a triaxial testing machine which measures the axial load and the axial strain. From this the Young's modulus is calculated. In a perfect material the stress-strain curve is linear and the slope represents the Young's modulus (Figure 10).

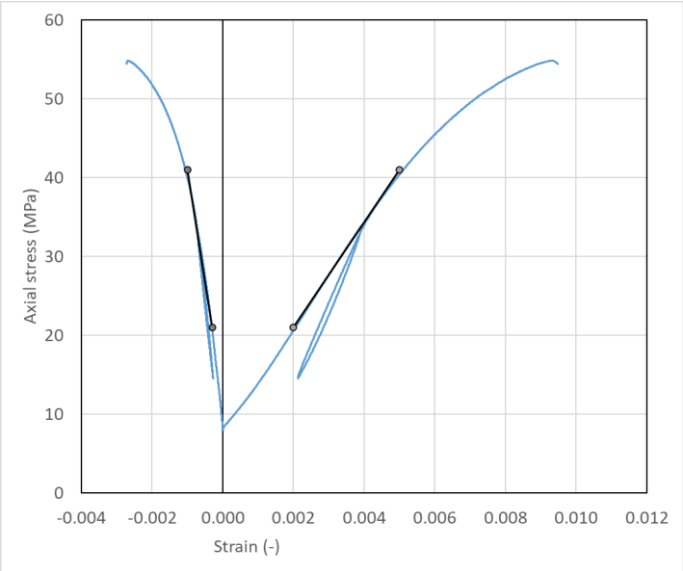


Figure 10: Stress-strain curve from triaxial tests. The solid black lines are used to determine the Young's modulus (slope of the right black line), and the Poisson's ratio (the ratio between the left and right slope). The curve on the left is the radial strain, on the right is axial strain.

In reality the stress-strain curve will not be straight due to processes such as crack-closure at lower stresses etc. Therefore it is advised to state how the Young's modulus is determined, and which part of the stress-strain curve is used.

E_{dyn} can also be measured in a test set-up using sonic wave velocities and density. It should be noted that if these measurements are used to compare with log derived values, then care has to be taken with respect to different frequencies in the lab versus well measurements.

Finally, the Young's modulus is confining pressure dependent. Which means that to be able to use the measured values in the rest of the workflow, they have to be measured at effective stresses that are representative for the reservoir conditions.

Log property calculation and calibration

There is no direct wellbore measurement of the Young's modulus. However, E_{dyn} can be calculated from measured sonic velocities (V_p and V_s) and density (ρ) in the wellbore:

$$E_{dyn} = \rho V_s^2 \left(\frac{3V_p^2 - 4V_s^2}{V_p^2 - V_s^2} \right)$$

V_p and V_s can be measured in the wellbore with a dipole sonic tool. The density measurements are discussed in paragraph 4.1.2.

Geomechanical models used for seismic risk and cap rock integrity analyses need static moduli instead of the dynamic one calculated above. Therefore a conversion is needed from E_{dyn} to E_{stat}. The conversion is applied at each depth level to obtain static Young's modulus throughout the well log.

The dynamic Young's modulus is generally higher than the static Young's modulus due to strain-rate effects. Empirical relationships based on core laboratory tests are used to make this conversion.

A common empirical formula is:

$$E_{stat} = A * (E_{dyn})^B + C$$

A, *B* and *C* are lithology and case dependent empirical constants and are typically obtained from laboratory testing on core samples from the same reservoir. The equitation can be expanded by including extra guiding parameters such as porosity to improve the predictive power.[18]

If enough test data is available then a case specific relationship can be obtained and used. However, in most cases a published relationship will need to be used to convert E_{dyn} to E_{stat}. See Appendix 6: Young's Modulus for examples of these published equations.

If there is no shear wave velocity data available, then an artificial Vs curve can be created by using a V_p to V_s correlation. Castagna et al. (1993) published several equations which are commonly used for this. For cleaner sandstones the following correlation can be used: $V_s = 0.8042 \cdot V_p - 0.8559$ [km/s] and for clay-rich formations the general "Castagna mudrock line" can be used: $V_s = 0.8621 \cdot V_p - 1.1724$ [km/s].

Upscaling

To upscale the Young's modulus to reservoir scale we have to define the best averaging method. We are looking for a method which produces a single value for E_{stat} because most of the tools used in geothermal exploration can't handle tensorial input. Voigt (1889)[19] proposed to use the arithmetic mean, and Ruess (1929)[20] proposed the harmonic mean for averaging the bulk and shear moduli. The results of these methods can be seen as the upper and lower bound, where the actual value will somewhere in between. Hill (1963)[21] proposed to use the average of the arithmetic and harmonic mean when no reliable information is available on layering, which seems to be a reasonable approach to obtain the most probable number. The Voigt and Ruess bounds can be used as a first approximation of the uncertainty. This uncertainty can be larger when taking into account the source and quality of the input data for the averaging.

Upscaling calibration

There is no well test known that is dedicated to measuring the Young's modulus of a reservoir in a wellbore. In some cases the average Young's modulus can be estimated using the wellbore compressibility from a leak-off test and an estimated Poisson's ratio. See the section on Rock compressibility for more information on the compressibility calibration.

Another calibration option is the use of 3D geomechanical models if significant subsidence is expected. In that case the predicted subsidence is compared with the measured subsidence. If the subsidence is predicted correctly, then the model parameters are consistent with the observation. However, this is solving a problem with a non-unique solution. This means that there could be a match for the wrong reasons, and derived parameters have to be used with care.

More detailed description on Young's modulus measurements and upscaling can be found in Appendix 6: Young's Modulus.

---

[18] Asef & Farrokhrouz (2017). A semi-empirical relation between static and dynamic elastic modulus. Journal of Petroleum Science and Engineering 157. p. 359–363. http://dx.doi.org/10.1016/j.petrol.2017.06.055

[19] Über die Beziehung zwischen den beiden Elastizitätkonstanten isotroper Körper. Annals of Physics 38, 573–587

[20] Calculation of the flow limits of mixed crystals on the basis of the plasticity of mono-crystals. Zeitschrift für Angewandte Mathematik und Mechanik 9, 49–58

[21] Elastic properties of reinforced solids: some theoretical principles. J. Mech. Phys. Solids 11, 357-372

Poisson's ratio

Poisson's ratio determines how the horizontal total stress is changing due to pore pressure changes, the so-called stress path $\gamma_h = \alpha \frac{1-2\upsilon}{1-\upsilon}$ and it is a parameter in calculation of the stress change due to temperature change $\frac{\Delta\sigma_h}{\Delta T} = \frac{E}{1-\nu}\beta$. From the WarmingUp study[22] and KEM-15[23] we can conclude that the Poisson's ratio has a medium importance for seismic risk, and a low importance for cap rock integrity assessment.

However, some techniques use Poisson's ratio for horizontal stress (σ_h) calculations, and $\sigma_h$is an important input parameter for both seismic risk and cap rock integrity assessment. Therefore it is important to estimate the Poisson's ratio as well as possible.

Measurement

The Poisson's ratio is commonly measured in the lab where a sample is subjected to a vertical load, and simultaneously the vertical and horizontal strain are measured. The ratio between horizontal strain (ε_h) and vertical strain (ε_v) in the elastic domain is the Poisson's ratio (ν).

$$\nu = \frac{\varepsilon_h}{\varepsilon_v}$$

The Poisson's ratio is an elastic material parameter, therefore it is important that the strain measurements are taken from the elastic part of the stress-strain curve (Figure 10). Unfortunately, laboratory test do not always produce linear axial and radial strain curves, which makes the determination of the Poisson's ratio dependent on which part of the curve is used. This will lead to a certain amount of uncertainty in the final Poisson's ratio value.

Log property calculation and calibration

Poisson's ratio can't be directly measured in a wellbore. However, the dynamic Poisson's ratio can be calculated from wireline or LWD data using the compressional and shear wave velocity (V_p and V_s).

$$\upsilon_{dyn} = \frac{V_p^2 - 2V_s^2}{2\left(V_p^2 - V_s^2\right)}$$

There is no common method for converting the dynamic Poisson's ratio into a static Poisson's ratio. The methods used are ranging from assuming no converting ($\upsilon_{stat} = \upsilon_{dyn}$) to correcting from undrained to drained using poro-elasticity equations[24] to using empirical relationships (including other log values such as porosity)[25]. Knowing the uncertainty in determining the static Poisson's ratio, we should be careful not to spend too much effort on the Poisson's ratio correction, and concentrate on defining a reasonable uncertainty margin to be used in the stochastic analyses.

---

[22] warmingup4b1_report_r1_quantification_of_induced_seismicity_potential_of_geothermal_operations.pdf

[23] https://kemprogramma.nl/blog/view/5a3ab959-6f72-4e34-9ba7-9af80a7d8be0/kem-15-seismic-risk-due-to-cooling-effects-in-geothermal-systems-finished

[24] Hettema, 2022. Practical workflow for assessment of seismic hazard in low enthalpy geothermal systems. Geomech. Geophys. Geo-energ. Geo-resour. (2022) 8 https://doi.org/10.1007/s40948-022-00478-z

[25] Feng et al. 2019. A new empirical method based on piecewise linear model to predict static Poisson's ratio via well logs. Journal of Petroleum Science and Engineering Volume 175, p1-8. https://doi.org/10.1016/j.petrol.2018.11.062

In the case of absence of V_s data, this can be created using the V_p curve. More explanation is given in the paragraph on Young's Modulus (E).

There have been efforts to predict the Poisson's in the total absence of velocity data. These techniques use the available logging data and/or are based on drilling parameters using machine learning tools.[26]

Upscaling

There are no common methods for upscaling the Poisson's ratio from logs to the whole reservoir section. It is safe to assume that an upscaled value between the bounds of the arithmetic and harmonic mean can be used in the models. If no other information or guidance is available then it is proposed to use the middle between these two bounds as the upscaled Poisson's ratio ($\upsilon_{upscaled}$):

$$\upsilon_{upscaled} = \frac{\upsilon_{arithmetic\ mean} + \upsilon_{harmonic\ mean}}{2}$$

Upscaling calibration

Unfortunately there is no method to calibrate or check the upscaled Poisson's ratio versus a well test or other model.

Rock compressibility

In contrast to hydrocarbon industry, rock compressibility is not of major importance in flow modelling for geothermal operations. In hydrocarbon reservoir engineering rock (or better pore) compressibility is used to update pore space with declining pore pressures during production. Geothermal operation has only limited effect on the pore pressure, and therefore on the change in pore space. Therefore compressibility is not an input parameter in DoubletCalc. However, rock compressibility is important for estimating effects such as subsidence. Furthermore, compressibility can be used a direct measure of the elasticity of the reservoir. Therefore, this parameter is often required as input in estimating the long term effects of a geothermal projects (e.g. SHRA)

The rock compressibility is not an independent parameter. The compressibility is 1/bulk modulus, therefore the rock bulk compressibility (1/MPa) can be calculated from the Young's modulus and Poisson's ratio.

$$C = \frac{3(1-2\nu)}{E}$$

Measurement

Rock compressibility can be measured in the lab. There are several methods to do this. When using lab compressibility data it is important to understand the test set-up. In some cases the measurement data is processed assuming that the rock grains are incompressible which can cause a significant discrepancy with the actual compressibility[27].

[26] Siddig et al., 2021. Real-time prediction of Poisson's ratio from drilling parameters using machine learning tools. Sci Rep 11, 12611 (2021). https://doi.org/10.1038/s41598-021-92082-6

[27] Schutjens & Heidug (2012). On the pore volume compressibility and its application as a petrophysical parameter. 9th Biennial International Conference & Exposition on Petroleum Geophysics.

Log property calculation and calibration

There have been attempts to calculate a compressibility log from wireline or LWD logs using empirical relationships[28]. However, it is probably better to estimate the compressibility using Young's modulus and Poisson's ratio. The bulk modulus can be calculated from E and ν as described above. This will produce the elastic compressibility, which will be enough because no or little plastic deformation is expected due to the limited pressure decrease.

Upscaling

The compressibility expressed as bulk modulus can be upscaled using the Voigt, Ruess or Hill methods as described in Young's Modulus (E)- Upscaling.

Upscaling calibration

There are several options to calibrate or check the upscaling, although they all are either not very common (dilatometer) or use a lot of assumptions which related uncertainties.

There are case studies in other fields then geothermal or conventional hydrocarbons where a dilatometer in a borehole was used to measure compressibility. Zalesky et al. (2007) used a dilatometer in exploration boreholes to characterize rocks for deep tunneling.[29] Marchina et al. (2004) used a dilatometer to characterize the sand formations in heavy oil exploitations.[30] However, it doesn't seem that this technology has developed further. The further development and application of a dilatometer for geothermal applications is unlikely due to the low value of information of this measurement.

Another method to estimate the reservoir compressibility is to achieve a good fit on your well test or reservoir flow model. In both models, the compressibility is an input parameter which influences the model outcome. When the model produces results close to the test then that means that there is a consistent set of parameters used. However, it doesn't necessarily mean that the calibration is right because those models have non-unique solutions as discussed with well testing for permeability calibration.

A last method is using the linear part of the LOT to determine the compressibility of the whole system. To be able to calculate the formation compressibility we have to deduct the well compressibility from the measurement. The well compressibility is estimated using the casing and cement stiffness and volumes. Thes estimates will have a significant uncertainty which has to be taken into account while using it for calibration.

---

[28] Hall (1953): COMPRESSIBIITY OF RESERVOIR ROCKS. Technical Note 149, PETROLEUM TRANSACTIONS, AIME Vol. 198. P309-311.
Ashena et al. (2020). Log-based rock compressibility estimation for Asmari carbonate formation. Journal of Petroleum Exploration and Production Technology (2020) 10:2771–2783. https://doi.org/10.1007/s13202-020-00934-0

[29] Zalesky et al. (2007): Dilatometer tests in deep boreholes in investigation for Brenner base tunnel. Underground Space – the 4th Dimension of Metropolises – Barták, Hrdina, Romancov & Zlámal (eds)

[30] Marchina et al. (2004). In situ measurement of rock compressibility in a heavy oil reservoir. International Thermal Operations and Heavy Oil Symposium (Itohos), 2004, Bakersfield, United States.

4.3.2 Biot coefficient [-]

The Biot coefficient (α) is defined as the ratio of the pore volume change to bulk volume change due stress or pore pressure.

$$\alpha = \frac{\Delta V_{pore}}{\Delta V_{bulk}}$$

But the Biot coefficient is better known as the parameter which describes how much pore pressure (P_p) influences the effective stress (σ_{eff}).

$$\sigma_{eff} = \sigma - \alpha P_p$$

The Biot coefficient is related to the bulk and grain compressibility:

$$\alpha = 1 - \frac{C_{bulk}}{C_{grain}}$$

The Biot coefficient will be higher for more porous rocks (or for rocks with a higher crack density). On average, sandstones will have a Biot coefficient between 0.6 – 1.0. There have been discussions what value to choose in rock failure or fault slip analyses. Several authors (e.g. Jaeger (2007)[31]) suggest to use a Biot coefficient of 1.0 for rock slip analysis.

Please note that although the Biot coefficient has a true physical meaning, it is unfortunately often used as a fudge factor to make models work without proper argumentation. In those cases those values have to be used with care since they don't have to be consistent with all the other parameters at all.

The effect of Biot coefficient on seismic risk and cap rock integrity assessment is low according the WarmingUp study using the SRIMA methodology. This is related to the fact that the cooling of the reservoir the largest effect on the normal stress. Biot Coefficient has no influence on that. The Biot coefficient relates how much the effective stress changes when the by pore pressure changes. In most cases the pore pressure changes have a limited effect on the fault stability. This means that the Biot coefficient has also a small effect.

The KEM15 study presents a significant effect of the Biot coefficient on the slip tendency, but that is solely caused by the method used on calculating the effective normal stress on the fault where a higher Biot coefficient results in a lower magnitude of effective normal stress which in turn produces higher slip tendency. This is because in software used projects effective stresses onto the fault. However, as the authors highlight themselves: "*the actual effective stress coefficient of a fault that influences its tendency to slip is different from Biot's coefficient. As a first order and more conservative estimate, one should assume an effective stress coefficient of 1 for the fault in future scenarios*". This means that high influence is pure caused by the initial effective stress state, and not the effect of the geothermal operations.

SRIMA is the mostly used software tool for the seismic hazard analysis in the geothermal domain in the Netherlands. In that workflow Biot Coefficient has only a minor effect. Other techniques or

[31] Jaeger et al. 2007 Fundamentals of Rock Mechanics, 4th Edition. ISBN: 978-0-632-05759-7

applications might show a higher dependence (e.g. KEM15), but it should be carefully checked if the used methodology captures the physics correctly.

Measurement

The Biot coefficient can be calculated from the bulk compressibility as measured in the lab and an measured or assumed grain compressibility using the equation listed above. This is only possible if the lab measurements are done slow enough so that the fluid pressure in the pores stay homogeneous throughout the sample, and can't locally increase due to the deformation (so called drained conditions). It important to really measure the drained behavior, otherwise not the rock compressibility is measured, but a combination of rock and fluid compressibility which can't be used in the workflows. Achieving drained conditions can be a challenge in low porosity formations. If measurement of the grain compressibility is not possible, then for a reliable calculation it is important to know the composition of the grains to be able to calculate the right grain compressibility. Without a good compositional analysis, the calculated Biot coefficient has to be used with care (e.g. use a wide enough uncertainty bandwidth).

Kasani & Selvadurai (2023)[32] give a good overview on the possibilities and limitations of the different test methods to derive the Biot coefficient.

Log property calculation and calibration

If there is a good quality calculated compressibility or Young's modulus and Poisson's ratio log then the Biot coefficient can be calculated using the equation above, together with an assumed grain compressibility. Other options are using empirical relationships such as Fabre & Gustkiewica (1997) and Van Eijs & Van der Wal (2017).

If using empirical relationships then it has to be checked if the resulting values are within expected bounds for those lithologies as published in literature (e.g. Kasani & Selvadurai (2023)[30]). If they are outside these bounds, then it is recommended to use the published bounds from literature.

Upscaling

There are no published best-practices with respect to upscaling the Biot coefficient. Since the value range won't be significant, and the fact that the effect on the seismic risk and cap rock integrity assessment is small, it is proposed to use the arithmetic mean as the upscaled Biot coefficient.

Upscaling calibration

There is no reliable method to calibrate or check the upscaled Biot coefficient versus a well or other field test.

4.3.3 Linear thermal expansion coefficient

As mentioned before, the linear thermal expansion coefficient has a high importance for both seismic risk and cap rock integrity analyses. This is confirmed in both the WarmingUp and the KEM-15 study. The thermal expansion coefficient is important for the reservoir formation in the seismic risk analyses, and an important parameter of the seal for cap rock integrity studies.

[32] Kasani & Selvadurai (2023). Review of Techniques for Measuring the Biot Coefficient and Other Effective Stress Parameters for Fluid-Saturated Rocks. Applied Mechanics Reviews. Vol. 75 / p 020801-1 – 24. https://www.mcgill.ca/civil/files/civil/338.pdf

Thermal expansion is the tendency of a material to change in shape and volume when subjected to a temperature change. For isotropic materials like gases, liquids, and cubic solids, this expansion is uniform in all directions and can be described using a single parameter. However, anisotropic materials, such as crystalline solids with lower symmetries, expand differently along different axes, requiring multiple parameters for a full description.

The linear thermal expansion coefficient (β_L) is the change in length per change in temperature normalized by the original length.

$$\beta_L = \frac{\Delta l}{\Delta T} \cdot \frac{1}{l}$$

It should be noted that the thermal expansion coefficient can also be reported as a volumetric expansion coefficient (β_V). The relation between linear and volumetric expansion coefficient is $\beta_V = 3\beta_L$ for isotropic materials or randomly orientated aggregates.

In a rock, the thermal expansion coefficient is determined by the expansion coefficients from the individual rock grains, where it should be noted that the linear expansion coefficient for crystals is different for the different crystal axes. The thermal expansion coefficient is strongly related to the quartz content of the rock, because quartz has an order of magnitude higher expansion coefficient as most other rock forming minerals. It is commonly assumed that the porosity has little effect on the thermal expansion coefficient.

Measurement

The linear thermal expansion coefficient is determined in the lab by measuring the length change of the rock sample with changing temperature. Similarly, the volumetric expansion coefficient is determined by measuring the volume change.

To determine the rock expansion coefficient it is important that the measurements are performed drained. However, for low permeable rocks the measured values can be influenced by the expansion of the pore fluids that can't escape the sample in the timescale of the experiment. In that case higher expansion coefficients could be measured, because the expansion coefficient of water is higher than that of rock. It should also be noted that the thermal expansion of a rock cannot be measured reliably above about 100 °C without applying confining pressure to the rock sample because of phase changes of the pore fluids and internal micro-cracking caused by the different expansion coefficients of the different minerals.

Log property calculation and calibration

There is no published method for determining the thermal expansion coefficient from log measurements.

However, an estimate of the thermal expansion coefficient can be made from (estimated) mineralogy and then especially the quartz content of the rock of interest as described above. To estimate the thermal expansion based on mineralogy, a weighted average method based on the thermal expansion coefficients of the most abundant minerals in sedimentary rocks can be used. The formula is given by:

$$\beta_{sed} = \Sigma(f_i * \alpha_i)$$

where:

β_{sed}	Mean thermal expansion coefficient of the sediment ($°C^{-1}$)
f_i	Volume fraction (or weight fraction) of the i-th mineral in the sediment
α_i	Thermal expansion coefficient of the i-th mineral ($°C^{-1}$)
n	Number of minerals considered

The mineralogy can be estimated from analyses on cuttings and cavings. Cuttings are always available for every drilled well, and the mineralogy measurements are relatively cheap in comparison to downhole measurements.

The expansion coefficient for these individual minerals can be found in literature. A list of common materials is given in the Appendix 8: Thermal properties.

Upscaling

Depending on the direction of interest, the arithmetic or harmonic mean can be used to upscale the linear thermal expansion coefficient. In most cases the average of these two will be a valid value to be used in seismic risk analyses and cap rock integrity studies.

Care should be taken for formations with discontinuities at faults, joints and fractures, foliation etc. because these will lower the actual expansion coefficient. Therefore the upscaled expansion coefficient might be too high when applied to large rock masses containing these features.

Upscaling calibration

There are no methods published on calibrating the upscaled expansion coefficient.

4.3.4 Unconfined Compressive Strength (UCS)

The unconfined compressive strength (UCS) is a metric describing rock strength. It is the axial stress needed to fail a rock sample in an uniaxial unconfined test. UCS doesn't fully describe the rock strength, because the internal friction angle describes the strengthening of the rock due to confining pressure. However, UCS is commonly used in certain workflows estimating the sand production potential or (in combination with the internal friction angle) in wellbore stability studies.

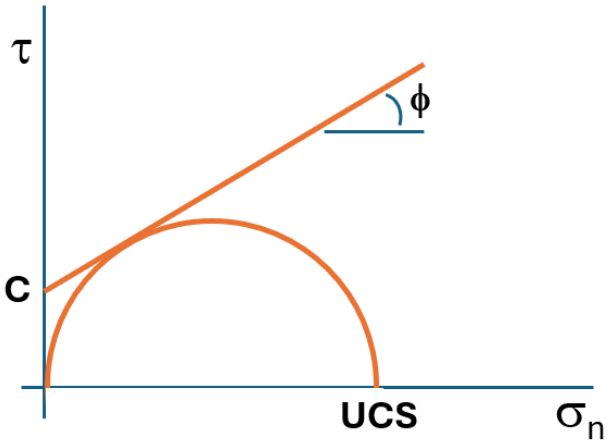


Figure 11: De relation between cohesion (C), internal friction angle (ϕ) and UCS in Mohr-space. σ_n is normal stress, τ is shear stress.

Measurement

The UCS can be measured in a lab using a uniaxial or triaxial press. To determine the UCS, the sample is axially loaded without any confinement. Normally the sample fails catastrophically. Pre-existing cracks or planes of weakness have a large effect in unconfined tests. Therefore, often the UCS is determined by testing multiple samples with confinement and then calculate the internal friction angle and cohesion and from those values the UCS (as shown in Figure 11).

Another method to measure the UCS is the so-called scratch test. The scratch test is a quasi-non-destructive method where a tool is pushed across the surface of a rock at a given penetration depth. From the penetration depth combined with the force needed, the UCS is estimated. Different labs use different machines and UCS calculations from the force and penetration depth. The disadvantage of this method that the UCS is not directly measured, but inferred from the force of scratching which is not exactly the same as pressing a sample to failure. However, the big advantage of this method is that one can obtain a continuous UCS log along the core, while only creating a small scratch leaving the core available for other tests.

Log property calculation and calibration

There is no logging tool that measures the UCS directly in a well. However, there are many empirical relationships that estimate the UCS from well log data. Several of these relationships are listed in Appendix 7: Unconfined Compressive Strength (UCS).

The calibration of the logging data is done by plotting the measured UCS values on the derived log. Care has to be taken to obtain the right core-shift for the measured data

Upscaling

UCS is normally not upscaled to a single value per larger intervals because most applications are done on log scale using the calculated UCS-log as input (e.g. sand production prediction and well bore stability).

Upscaling calibration

No upscaled calibration is needed, since the logs are normally not upscaled to larger intervals.

More detailed description on density measurements and upscaling can be found in Appendix 7: Unconfined Compressive Strength (UCS).

4.4 Thermal properties

The thermal properties of the rock are important in modeling the potential power of a geothermal system. In this report we look at the following properties:

1. Specific heat capacity rock [J/kg/K]
2. Thermal conductivity rock matrix [W/m/K]
3. Thermal diffusivity rock matrix [m2/s]

The first two properties are important to calculate how fast the formations around an injector well will cool. This is described by the thermal diffusivity (α), which can be calculated using the Specific heat capacity (C_p), Thermal conductivity (λ) and the density (ρ):

$$\alpha = \frac{\lambda}{\rho \cdot C_p}$$

Because there is a strong dependence between these parameters, there will be a lot of repetition in the sections below, where each of them is described individually. The measurement techniques are very similar between the parameters, and are quite often performed simultaneously as described in the International Society for Rock Mechanics (ISRM) suggested methods for determining thermal properties of rocks from laboratory tests. [33]

4.4.1 Specific heat capacity rock

The specific heat capacity (C_p) is the amount of heat that must be added to one unit of mass of the rock in order to cause an increase of one unit in temperature. The heat capacity is important parameter because it determines how fast a rock can cool when in contact with colder injection fluid. The higher the heat capacity, the more heat it can store. Heat capacity combined with the thermal conductivity also determine the effectiveness of a closed loop system where all energy is coming either from the heat already stored in the rock, or conducted towards the loop.

In some situations we refer to the specific heat capacity per unit volume of substance (thermal capacity), which is obtained by multiplying the specific heat capacity by the bulk density. By using the bulk density the porosity of the rock is taken into account.

$$Thermal\ capacity = C_p \cdot \rho$$

Measurement

The specific heat capacity can be measured on rock plugs or cuttings for example with the method described in ASTM D4611 – 16[34] .However, the measurement process is not straight forward. Measured heat capacities of rocks include the heat capacities of any pore fluids present in the samples analyzed. Because the specific heat capacity of water is higher than that of any mineral, the measured heat capacities of porous, (partly saturated) rocks do not give a good indication of the heat capacities of the rock matrix. Therefore, measured data obtained from rocks with significant porosity have to be used with care. Besides the porosity, the heat capacity is also changing with temperature. Therefore it is important to know at which temperature the heat capacity data is measured or calculated.

Because the measurement of the heat capacity of rocks is cumbersome, most of the time the heat capacity of a rock is calculated from the heat capacity of the individual minerals it contains. The calculation of the specific heat C_p of a rock at selected temperature can be made using the weighted average using the equation 1 below.

$$C_p = (x_n \cdot C_n) \cdot (1 - \phi) = (x_1 \cdot C_1 + x_2 \cdot C_2 + \cdots) \cdot (1 - \phi)$$

where x_n, (n = 1, 2, ...) is the volumetric fraction of the content of minerals 1, 2, ... and C_n is the specific heat per unit volume of the corresponding mineral constituent at a selected temperature. To account for the pore volume, C_p is multiplied with the solidity $(1 - \phi)$ where ϕ is the porosity.

[33] https://doi.org/10.1007/s00603-016-1070-5

[34] https://doi.org/10.1520/D4611-16

The composition of the rock can be measured on core samples or on cuttings/cavings with for example XRD. The mineral specific heat capacity can be found in literature[35].

Log property calculation and calibration

There is no direct measurement technique to measure the in-situ specific heat capacity. The best way is to calculate the specific heat capacity through the mineralogical content. This can be based on a constructed a lithology/mineralogy column, geochemical logging tools (e.g. Lithoscanner from Schlumberger or FLeX from Baker Hughes), or mudlogging on the cuttings, preferably combined with mineralogy measurements on them.

Based on the method of calculating the heat capacity from composition, Fuchs et al. (2015)[36] have derived relationships based on a standard logging suite and a synthetic data set of matrix compositions. This method delivers continuous specific heat capacity logs. It should be noted that these logs do contain a certain amount of uncertainty due to the global level at which they are derived.

Upscaling

There are no published relationships in upscaling the specific heat capacity. However, it seems logical to use the arithmetic mean to calculate the specific heat capacity, similar as described above to calculate specific heat capacity from the mineralogy.

Upscaling calibration

There is no published calibration of the upscaled specific heat capacity.

4.4.2 Thermal conductivity rock matrix

Thermal conductivity is important because it determines the heat flux through a material. This especially important for heat flux calculations where there is no convective heat transport (heat transport through the flowing pore fluid). In most geothermal systems the thermal conductivity is important to calculate the cooling of the cap rock, and therefore an important parameter for calculating cap rock integrity. The thermal conductivity is also important in closed-loop systems where most of the heat transport is conductive because there is no forced pore fluid circulation.

Measurement

The thermal conductivity can be measured in the lab with the optical scanning technique. The optical scanning technique involves scanning a sample's surface with a mobile heat source (typically optical or laser-based) while using infrared sensors to measure resulting temperature variations, which are then used to calculate thermal conductivity and diffusivity. This contactless method is effective for analyzing rock heterogeneity, anisotropy, and variability in thermal properties across large and/or irregularly shaped samples under ambient conditions.

Another methods for measurements of the thermal conductivity is the Hotdisk method. In this method a foil is used as both a heat source and a thermometer. This foil is placed between two sample pieces. A current is applied to the foil, and the resulting temperature increase is monitored.

[35] An example of measured specific heat for many minerals can be found in the USGS repository: https://pubs.usgs.gov/of/1988/0441/report.pdf
[36] https://doi.org/10.1093/gji/ggv403

These measurements are used to determine thermal conductivity, thermal diffusivity, and specific heat capacity of the sample pieces.

The thermal conductivity can also be measured with the linear line source technique. This technique involves inserting a needle with contains both a heating element and a temperature sensors into the sample. By monitoring the temperature response over time, the thermal conductivity can be calculated.

Depending on the measurement technique this is either done on core plugs or directly on the (slabbed) core. The thermal conductivity is influenced by the pore fluids in the pores due to the significant difference in conductivity between water and the rock.[37] Therefore, care has to be taken when comparing measurements on wet and (partially) dried samples.

Log property calculation and calibration

Several methods have been developed to measure in-situ conductivity.

- For shallow boreholes (up till 400m depth) an ISO norm is developed which measures the thermal conductivity using a borehole heat exchanger[38].
- Another method using a wellbore heater has been applied in the ultra-deep well of KTB[39].The thermal conductivity of formations can also be estimated using measured temperature profiles. A good example of this method is given in the TNO report on developing the ThermoGIS maps[40].

Upscaling

There are different methods to upscale the thermal conductivity to a reservoir scale. Below the most common ones.

The upscaling of the thermal conductivity is done similar to the permeability upscaling. As a general rule Arithmetic averaging is used when the heat flow is parallel to the layering. For the horizontal heat flow this can thus be used for most sedimentary rocks due to the horizontal bedding and general laminar layering. The harmonic average is more representative when heat flow is perpendicular to the layering. In most cases this is thus used to upscale vertical heat flow. As a third option, the geometric average can be used when there is no apparent preference for vertical or horizontal heat flow, the rock has no significant anisotropy for flow.

Upscaling calibration

The upscaled thermal conductivity can be checked using temperature profiles in the well. Care has to be taken that this doesn't cause a circle-reference in the case that the thermal conductivity is calculated from the same temperature profiles. In the case that the thermal conductivity is calculated from temperature profiles, then there is no published method to calibrate these.

[37] USGS Open-File Report 88-441 p.8
[38] ISO 17628:2015(en) Geotechnical investigation and testing — Geothermal testing — Determination of thermal conductivity of soil and rock using a borehole heat exchanger
[39] https://doi.org/10.2312/ktb.90-6a
[40] https://www.thermogis.nl/en/publications

4.4.3 Thermal diffusivity rock matrix

Thermal diffusivity is physically linked to heat capacity (C_p), conductivity (λ) and density (ρ) $\alpha = \frac{\lambda}{\rho \cdot C_p}$. To maintain a coherent system it is advised to use those upscaled values to calculate upscaled diffusivity.

Measurement

As described above, the thermal diffusivity is physically linked to heat capacity, conductivity and density. Measurement techniques are often giving these three thermal parameters. Therefore see for measurement techniques the paragraphs above.

Log property calculation and calibration

Log properties can be generated using the relationship given above.

Upscaling

It is better to calculate the upscaled value from the upscaled conductivity, heat capacity and density then to perform a new upscaling, to avoid creating a non-coherent system.

Upscaling calibration

There are no published methods to calibrated the Thermal diffusivity.

4.5 Geomechanical and thermal parameters

The geomechanical and thermal parameters are a “result” of (a combination of) the material properties discussed above and other forces such as gravity. Examples are:

- Pore pressure
- Vertical stress
- S_{hmin}
- S_{Hmax} magnitude and direction
- Geothermal gradient

These parameters are (often) smoother then the material properties they are derived from and have a certain direction (e.g. increase in vertical stress with depth).

4.5.1 Pore Pressure

The pore pressure is a continuous profile from surface to reservoir depth. The pore pressure is an important parameter in determining the mud weight in the drilling phase of well. However, the focus of this report is more on seismic risk and seal integrity. For those analyses only the pore pressure in the reservoir and caprock are of real interest. Therefore methods to derive pore pressure in the overburden from seismic cubes or sonic logs will not be discussed here. These techniques have the boundary condition that the sediments are normally compacted (i.e. there has only be burial, and no uplift), which is not case for most of the Dutch subsurface and geothermal targets.

In most cases the pore pressure in the reservoir can be obtained using the available well test data. If the wellbore is in equilibrium with the reservoir, then the pore pressure at depth z can be calculated

using de fluid density (ρ_{fl}) and the depth of the water table (z_{wt}) when the well is in equilibrium (e.g. static water level):

$$P_p = \rho_{fl} \cdot g \cdot (z - z_{wt})$$

4.5.2 Vertical stress

Calculating the vertical stress is quite trivial. The vertical stress is integrating the density log over the true vertical depth.

$$S_v = \int_0^z \rho(z) \cdot g \cdot \delta z \approx \bar{\rho} \cdot g \cdot z$$

While calculating the overburden stress seems easy, it is important to do it carefully, because it can have a strong effect on the calculated minimum and maximum horizontal stresses. It is important to have a good quality density log as described in section 4.1.2. Unfortunately density data is often not available in the shallower part of the borehole. In these cases, one should use the local geological information to estimate the missing data. If available, offset data from similar formations can be used. If no offset data is available, then as a rule of thumb, it is assumed that the density at surface is around 2.1 g/cm^3. Please note that the density profile of the shallower sections can have profound impact on the calculated overburden stress magnitude at reservoir depths. When estimating the densities for sections without logging data, it is important to see if lithologic changes are present, especially those that have a strong density variation, like anhydrite (2.8-3.0 g/cm^3) or carbonate intervals (2.5-2.8 g/cm^3).

A practical way of calculating the overburden stress is to calculate the arithmetic average density for every formation, or several depth intervals with similar densities, and then add these together:

$$S_v = \rho_1 \cdot g \cdot z_1 + \rho_2 \cdot g \cdot z_2 + \cdots + \rho_n \cdot g \cdot z_n$$

4.5.3 Minimum horizontal stress (S_{hmin})

The minimum horizontal stress (S_{hmin}) is one of the parameters that has a large effect on seismic risk and cap rock integrity calculations (see WarmingUp). Therefore it is important to estimate this parameter carefully. The best method to estimate the minimum horizontal stress profile is by using an effective stress ratio which calibrated to well measurements.

Measurement

The measurements of S_{hmin} in a wellbore are:

- (Extended) leak-off test ((X)LOT)
- Minifrac test

Both tests are relatively similar. In both cases a part of the wellbore is pressurized and it is monitored how the pressure develops per pumped volume of fluid (Figure 12). The response between volume pumped and pressure is linear as long as the wellbore is not fracturing. As soon as a fracture initiates, the response will deviate from linear. In the case the test only shows the linear part then it is called a limit test (LT) or formation integrity test (FIT) or formation strength test (FST). The

LT/FIT/FST is not a measurement of the S_{hmin}, but it can help guiding a S_{hmin} profile, since it is very likely that the S_{hmin} will be higher than the measured pressure during the LT/FIT/FST test.

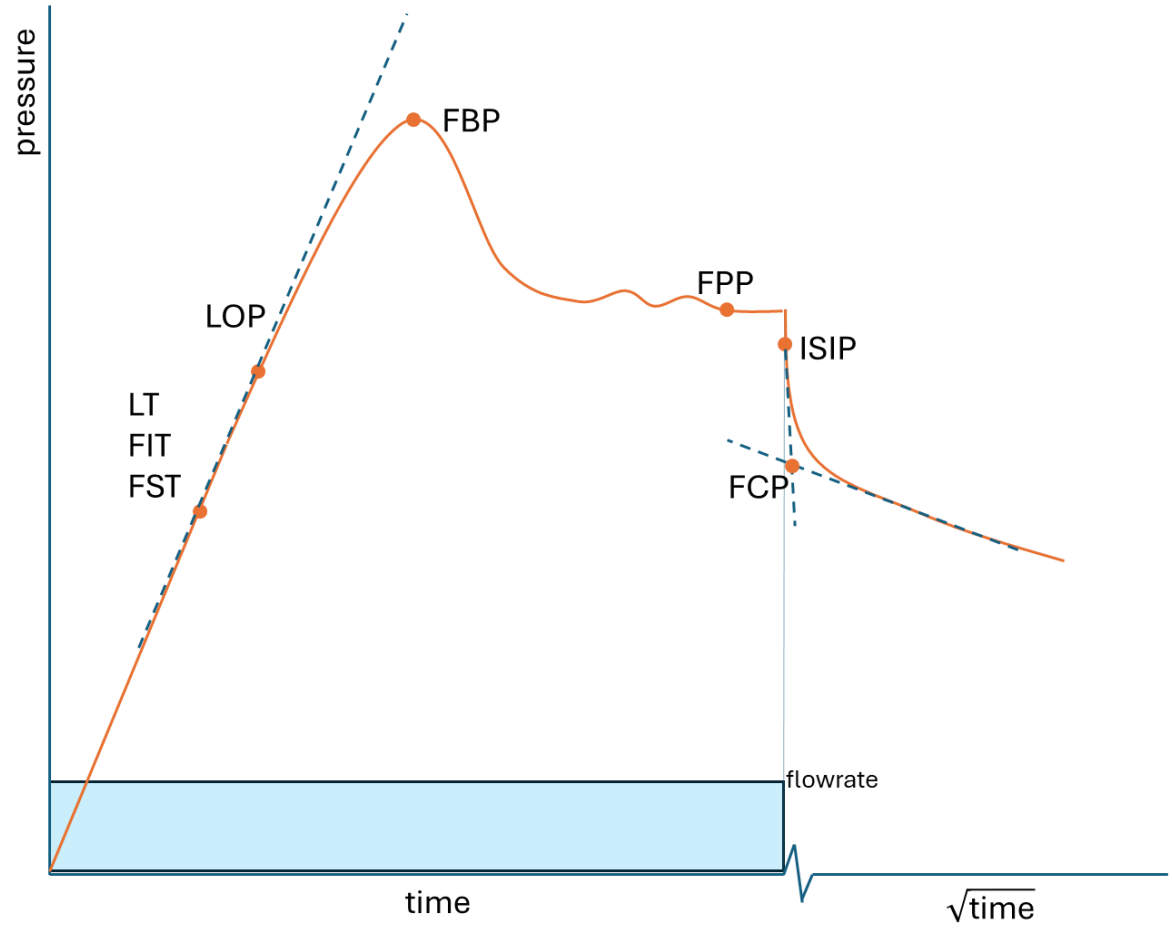


Figure 12: Schematic graph of an extended leak off test. A fluid is pumped with a constant rate in a well. The pressure response is measured. The test can be stopped at different moments, giving you different parameters. Please note that to determine the fracture closure pressure, the pressure-time curve should be plotted with a $\sqrt{time}$ at the x-axis, with the shut-in as t=0. LT=limit test, FIT=formation integrity test, FST=formation strength test, LOP=leak of pressure, FBP=formation breakdown pressure, FPP=fracture propagation pressure. ISIP=instantaneous shut-in pressure, FCP=Fracture closure pressure.

In absence of well test data, it might be worthwhile to read the daily drilling reports for indications of fracturing such as losses and ballooning incidents. Not all losses are related to fracturing, but the daily drilling reports can give information regarding the most logical causes of the losses. The used mud weight at the time of the fracturing is an indication of the S_{hmin} in equivalent mud weight (EMW).

Upscaling to log

The most efficient way to create a S_{hmin} profile is using an effective stress ratio (ESR). An effective stress ratio is the ration between the effective horizontal stress and the effective vertical stress:

$$ESR = \frac{S_{hmin} - P_p}{S_v - P_p}$$

The use of an ESR helps to get a stress model where the S_{hmin} increases with increasing overburden pressure as often is observed. It also always generates a consistent stress model where the S_{hmin} is

always higher than the pore pressure. In normal pressured systems this is also easily achieved with a total stress ratio, but in cases with an elevated pore pressure it might be a challenge to always obtain a consistent stress model.

To calibrate the ESR, the vertical stress and pore pressure profiles are plotted together with the well test data from the well of interest together with offset FIT & (X)LOT data. Then a S_{hmin} curve is generated for a chosen ESR. The ESR is adapted such that the calculated S_{hmin} log is above most of the LT/FIT/FST points and close to LOP or FCP points (the definition of these points is given in Figure 12).

A method often found in literature is calculating the ESR using the Poisson's ratio ($ESR = \frac{\upsilon}{1-\upsilon}$). The S_{hmin} calculated with this method quite often underestimates LOT data, therefore an extra term "tectonic strain" is introduced for further calibration. Although this method is physically not correct, it might match the S_{hmin} in certain cases (Eaton 1969). But with the introduction of the "tectonic strain" calibration factor it isn't a better method than using a more upscaled ESR ratio per formation.

4.5.4 S_{Hmax} magnitude and direction

S_{Hmax} magnitude

To estimate the magnitude of the maximum horizontal stress (S_{Hmax}) many parameters have to be combined. The workflow for determining the S_{Hmax} is rather complex and very dependent on the available data. To work with this workflow it is best to use dedicated paper or book, like Reservoir Geomechanics by Mark Zoback[41].

A more qualitative approach is to check if there is information on borehole breakouts or drilling induced tensile fractures. This information can come from 4 or 6 arm caliper, image and dipmeter logs. Care should be taken to filter for key seating (mechanical pipe wearing) and decentralized tools. If breakouts are detected in wells with a low inclination, then this is a sign of a significant difference between S_{Hmax} and S_{hmin}.

S_{Hmax} direction

If borehole breakouts are present then the S_{Hmax} direction can be determined from oriented log data such as image logs or multi arm caliper (4 or 6 arm). In absence of breakouts or this data, offset information can be used because the S_{Hmax} direction is not expected to vary strongly in a region. A well-known source of S_{Hmax} direction data is the World Stress Map project[42].

4.5.5 Geothermal gradient

The geothermal gradient is often required to get an estimation of the reservoir temperature during feasibility studies by converting the reservoir depth map to a reservoir temperature map. The geothermal gradient is often derived from temperature measurements or regional literature models.

Regional models

In the Netherlands there are two main geothermal gradient models, namely:

[41] Reservoir Geomechanics by Mark D. Zoback. https://doi.org/10.1017/CBO9780511586477
[42] World Stress Map - World Stress Map (world-stress-map.org)

- Reservoirs deeper than 1000 m. Bonté et al., (2012): 0.0313 °C/m + 10.1 °C (Figure 13) [43]
- Reservoirs shallower than 1000 m. Gies et al., (2021): 0.0215 °C/m + 10 °C [44]

Measurements and calibration

Alternatively, the geothermal gradient can also be calculated from representative measurements. This often results in better estimations. You can for example use the following data:

- Bottom Hole Temperatures (BHT) taken from EOW-reports and their corresponding depths.
- Temperature log data
- Direct temperature measurements from well test and geothermal production data

However, it should be noted that these measurements often need to be calibrated. Since temperature measurements often are an underestimation of the actual temperature. Correction of BHT can for example be done using the Horner, ICS or AAPG correction method (e.g. Bonté et al., 2012). Temperature log data can for example be corrected using the method proposed by Schumacher and Moeck (2020)[45].

Upscaling

Temperature measurements, corrected BHT and corrected log data can be converted to a geothermal gradient by plotting the data against the true vertical depth and performing a regression analysis. This often results in better temperature estimates with respect to estimates using regional models.

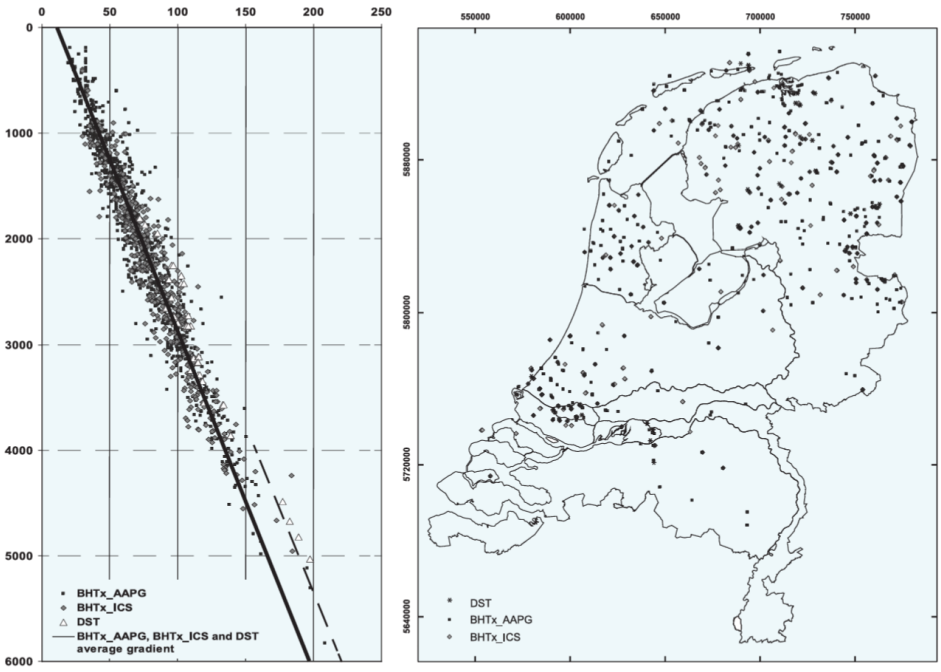


Figure 13: Dataset used to derive the regional temperature model (0,0313 °C/m + 10.1 °C) from Bonté et al., (2012). Figure from Bonté et al., (2012). Data can be downloaded from: https://www.nlog.nl/temperatuurgegevens.

[43] Bonte et al., (2012): Subsurface temperature of the onshore Netherlands: new temperature dataset and modelling. NJG (91-4)

[44] Gies et al., (2021): An effective method for paleo-temperature correction of 3D thermal models: A demonstration based on high resolution datasets in the Netherlands. Global and Planetary Change (199)

[45] Schumacher and Moeck (2020): A new method for correcting temperature log profiles in low-enthalpy plays. Geothermal Energy (8:27).

4.5.6 Calibration of Geomechanical Model

Besides pore pressure and minimum stress measurements, there is no direct measurement which allows to check if the geomechanical model is correct. However, the stress model, pore pressure and rock strength combined with observed break-outs or drilling induced tensile fractures (DITF) give the possibility to calibrate. Break-outs can be measured with 4 (or more) -arm caliper tools or image logs. DITF can be identified on image logs.

The stress state around a well bore parallel to a principle stress axis is described by the Kirsch (1898) equation. This stress state in combination with the rock strength allows to calculate which part of the well bore wall is above the failure criterion. This part probably falls out of the well bore wall creating the so-called break-outs. With certain combinations of mud weight and stress state, drilling induced tensile fractures can form along the axis of the well bore in the direction of S_{Hmax} . To create DITF a relatively large difference between S_{hmin} and S_{Hmax} is needed, often in combination with a (temporarily) high mud pressure. A temporarily high mud pressure can occur when (down) tripping in a hole too fast causing a pressure increase below the bit.

By comparing the predicted break-outs and DITFs with the actual measured break-outs or DITF allows for assessing the quality of the geomechanical model. If there are no caliper or image logs available then there is still the possibility to compare the predicted break outs and DITF with drilling events such as pack-offs (often caused by more cavings than the hole cleaning can handle) or losses during drilling. Therefore it is always very useful to collect this kind of information out of the daily drilling reports.

Another method to make sure that the modelled stress state is consistent with observed (or absence of) breakouts and DITF is the use of a so-called stress polygon. The stress polygon visualizes the range of possible magnitudes of S_{hmin} and S_{Hmax} for a given depth (and related vertical stress) and pore pressure. The bounds are based on the assumption that on the larger scale the stresses in the earth's crust are in a frictional equilibrium because the crust contains a large amount of widely distributed faults, fractures and planar discontinuities. Combining the stress polygon with observed breakouts or DITF at that depth allow to calibrate the geomechanical model. More detailed explanation is given in the Reservoir Geomechanics book of M. Zoback (2007).

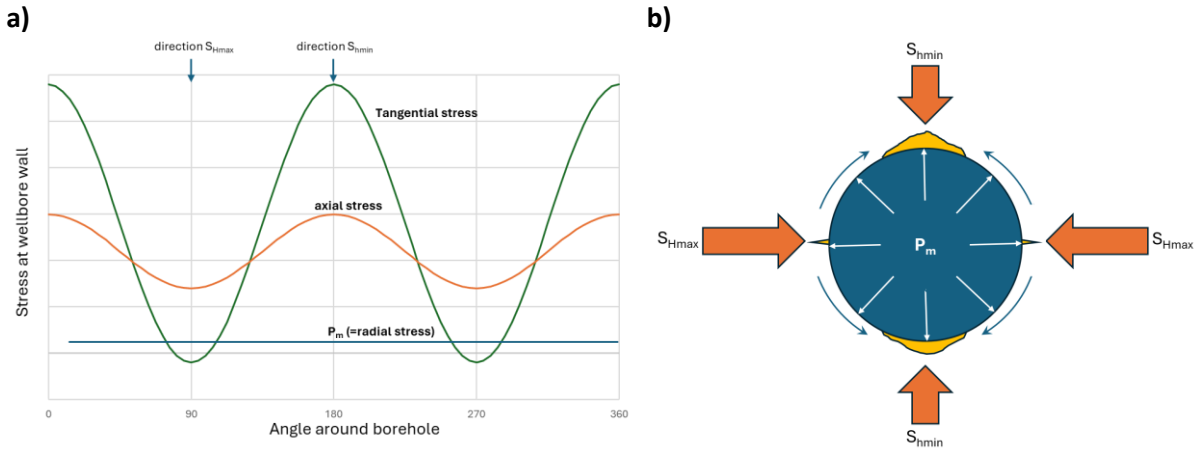


Figure 14: a) Effective stress state at the bore hole wall for a vertical well. Orange = stress at the bore hole wall parallel to the well bore axis, green = stress parallel to the bore hole wall and perpendicular to the wellbore axis, blue = stress perpendicular to the wellbore wall, which is caused by the mud weight. b) schematic view along the wellbore axis for a vertical well. Wellbore breakouts will in the direction of S_{hmin} if the stresses are high enough, and if there is significant difference between s_{hmin} and S_{Hmax}. Drilling induced tensile fractures will form in the direction of S_{Hmax} in certain stress states where there is a relatively large difference between S_{hmin} and S_{Hmax} often in combination with a (temporarily) high mud weight.

5 Data gathering program: practical tips for a for geothermal projects

5.1 Which additional data can be acquired and how do they reduce uncertainties?

As described in Chapter 3, drilling a data acquisition well is often out of budget for geothermal projects, meaning they rely on data that is already available. Properties needed for the SDE++ and SHRA reporting, as indicated in Table 1 can be assessed and/or estimated during the pre-drilling phase, but quite large uncertainties often remain. Therefore, acquiring new information on these properties can help to quantify and lower these uncertainties. This leads to better and more precise estimations on the thermal power and subsurface risks of a geothermal project. During a data gathering program, there are multiple ways to get measurements on these properties, each having a cost and resulting in a decrease in uncertainty (Table 3).

For example, you can use wireline logging and logging while drilling for getting direct/indirect measurements on certain flow - and geomechanical properties of the reservoir. Furthermore, if available on your project location or acquired during the drilling campaign, core data, rock samples and fluid samples can be used to get valuable and high-resolution measurements on a wide variety of reservoir properties. In addition, using different well test methods, detailed information on the large-scale reservoir properties can be acquired. Lastly, measurements from literature sources can always help in estimating and/or cross-referencing the properties when there is data gap and/or limited data available.

5.2 Value of Information: Which data should be collected in your project?

5.2.1 What is Value of Information (VoI)?

To determine if extra data gathering is useful, it can be useful to perform a Value of Information (VoI) analysis. VoI is a decision analytic method for quantifying the benefit of acquiring additional information with respect to the increase of project value. Summarized the method looks at the potential value of the project without the extra data and the value of the project with the extra data, and compares the difference with the cost of gathering the extra data. Since we can't exactly predict what the new data will be, it most often will be a calculation involving the differences in probability of success.

For example: if the minimum horizontal stress (S_{hmin}) has a large uncertainty, then it is likely that the maximum injection pressure will be limited by the P90 value of the S_{hmin} (90% of the possible S_{hmin} have a higher value than the P90 value) as described in the SHRA workflow (SRIMA software). This limited injection pressure probably leads to a lower injection rate which limits the heat production. By performing an (extended) leak-off test the uncertainty on the S_{hmin} is most likely reduced. With the reduction the P90, your S_{hmin} will be higher. This allows for higher injection pressures leading to

higher injection rates and heat production. If it is estimated that there is 50% chance on a 10 bar pressure increase, then the project value increases with 50% of the extra income due to the 10 bar increase. If that is more than the cost of the (X)LOT test then it is worthwhile to do the measurement. It is worthwhile to do this exercise for all parameters involved in the important parameters as listed in Table 1.

Table 3: Measurement tools generally used for getting information on the reservoir parameters relevant for the SDE++ and the SHRA

Parameter	Wireline log and/or logging while drilling										Core	Rock and fluid samples			Well test			Desk study	Impact on geothermal project			
	RHOB (€€)	NPHI (€€)	NMR (€€)	Vp (DT) (€€)	Vs (DTS) (€€)	GR (D)	ROP, LITHOLOG & CALIPER (D)	4 arm Caliper (€/€€)	RES (€€)	Image log (€€€)	Coring (€€€€) + Core measurements (€€)	XRD cuttings (D/€)	Fluid samples (D)	Temperature samples (D)	Well test (D/€€)	(X)LOT/FIT (€/€€)	Interference / Spinner test (€€€)	Literature / offset data interpretation (€)	Impact on thermal power	Impact on seismic risk	Impact on caprock integrity	Typical uncertainty (pre-drill)
Depth top reservoir [mTVD]	YC	YC		YC		Y	Y			Y		Y					YC	P	Low	Low	Low	Low
Thickness (gross) [m]	YC	YC		YC		Y	Y			Y		Y					YC	P	High	Low	Low	Low
Net/Gross [-]	YC	YC		YC		YC			E								Y	P	High	Low	Low	Low/Med
Porosity [-]	YC	YC	Y	YC		I	I		E		Y		I		P		P	P	Low	Low	Low	Low/Med
Permeability[mD]	P	P	YC	P		I	I		E		Y				Y		YC	E	High	Low	Med	Med/High
Salinity [ppm]							P		P				Y	I	Y			P	Med	Low	Low	Low/Med
Reservoir temperature [°C]														Y	Y			P	High	Low	Low	Low
Direction stress field [°]								Y		Y								P	Low	Low	Low	Med/High
Vertical Stress (SV) [MPa]	Y			P	P													P	Low	Low	Low	Low
Max. Horizontal Stress (SH) [MPa]							I	I		I						P		P	Low	Med	Low	High
Min. Horizontal Stress (Sh) [MPa]	P			P	P											Y		P	Low	High	High	Med/High
Heat capacity (rock) [J/kg/K]							P				Y	YC						P	Low	Low	Low	Low
Thermal conductivity (rock) [W/(m K)]							P				Y	YC						P	Low	Low	High	Low
Compressibility (rock) [1/Pa]	P	P		P	P						Y				P			E	Low	Low	Low	Med/High
Young's modulus [GPa]	P	P		P	P						Y				P			E	Low	High	High	Med/High
Poisson ratio [-]				P	P						Y							E	Low	Med	Med	Med
Biot coefficient [-]	P	P		P							Y				P			E	Low	Low	Med	Med
Thermal exp. coeff. [1/K]											Y	YC						P	Low	High	High	High
Friction coefficient [-]											Y							P	Low	High	High	Med
Unconf. Compr. Strength (UCS) [MPa]											Y							E	Low	Low	Low	Med/High

Y = **Yes**, measurement methodology is commonly used to derive the parameter. Gives high certainty. **YC** = **Yes**, measurement methodology is commonly used to derive the parameter. However, the measurement needs to be **combined** with the results from other measurements.

P = Measurement methodology can **partly** be used for deriving the parameter. Results can be uncertain, incomplete or need to be combined with models/relationships. **E** = measurement can give an **estimation** of the parameter. Results can be very uncertain.

I = Measurement is used as **input** for equations. Measurement **cannot** directly be used to estimate the parameter.

D = automatically acquired during drilling. € = Measurement relatively cheap. €€ = Measurement is relatively cheap when acquired during drilling campaign. €€€ = measurement is expensive due to duration/equipment needed. €€€€ = measurement is very expensive due to duration/equipment needed

5.2.2 Which measurements have a high VoI and are therefore relevant to your project?

As can be seen from Table 3, some parameters have a greater impact on the thermal power and subsurface risk than others. This impact per parameter is related to four factors:

1) The direct influence on geothermal power
2) The direct impact on estimating the risk on seismicity
3) The direct influence caprock integrity.
4) The typical uncertainty (pre-drill) associated with the parameter.

A parameter with low impact but high uncertainty is less significant than one with high impact and high uncertainty. Therefore, it can be beneficial to invest in additional measuring of parameters that have both high impact and high inherent pre-drill uncertainty. Often, these measurements are ~~be~~ on top of the measurements which are commonly done during drilling and development of geothermal wells (e.g. cuttings and logs from logging-while-drilling). Table 4 provides insight into which parameters might be worth investing in. The selection of parameter is based on at least one high impact classification and a med/high or high uncertainty qualification (Table 1).

Table 4: Selection of parameters that have the highest impact on thermal power, seismic risk or caprock integrity and have a med./high or high uncertainty. Having additional measurements of these properties can be beneficial in estimating doublet performance.

Parameter	Added value	Possible additional measurements	Uncertainty reduction	When do the measurements have high VoI?
Permeability (K) (Chapter: 4.2.1)	Permeability has a high impact on flow inside the reservoir given the maximum injection pressures, and therefore the thermal power	Permeability can be estimated/measured using the following: • Well test (D/€€) • Interference test (€€€) • Spinner test combined with well test (€€€) • Petrophysical logs (e.g. NMR, RHOB, DT) (€€) • Measurements from core data (€€)	**Well test**: Med./High **Interference test**: Med. **Spinner test combined with well test**: Med. **Petrophysical logs**: Med. **Core data**: High	Performing a good well test always has a high VoI, since it results in (in)direct measurements of reservoir permeability. Petrophysical logs can also have a decent VoI for estimating the reservoir permeability and correlating high permeable zones between wells. Core data only has a high VoI when you have large geothermal projects and/or a tricky geology.
Min. horizontal stress (S_{hmin}) (Chapter: 4.5.3)	Having direct measurement on the min horizontal stress magnitude helps in estimating the maximum injection pressures allowed within the reservoir.	The Min. horizontal stress can be estimated or measured using the following: • (Extended)-Leak-off-test (X)LOT (€€)	**(X)LOT test**: High	In marginal reservoirs (e.g. low thickness or low permeability), having estimates/direct measurements on the min horizontal stress can be really valuable since high injection pressures may be required. Projects which have a relatively thin cap may also profit from direct measurements of S_{hmin}.

Parameter	Added value	Possible additional measurements	Uncertainty reduction	When do the measurements have high VoI?
Young's Modulus (E) (Chapter: 4.3.1)	The Young's Modulus is a measure of reservoir stiffness. Having accurate measurements can help in better predicting the stress changes as a result of production and injection.	The Young's Modulus can be derived using the following: • Acoustic logs in combination with density log (RHOB, Vp & Vs) (€€) • Well test (derived from Compressibility) (D/€€) • Measurements from core data (€€)	**Acoustic logs**: Low. **Well test**: Low **Combining well test results with acoustic logs**: Low/med. **Core data**: Med/High	In marginal reservoirs (e.g. low thickness or low permeability), having estimates/direct measurements on the Young's Modulus can be really valuable since high injection pressures or lower injection temperatures may be required.
Thermal expansion coeff. (β) (Chapter 4.3.3)	Knowing the thermal expansion coefficient results in better estimations of the stress changes caused by cold water injection.	The thermal expansion coefficient can be estimated using the following: • Derived from mineralogical measurements from cuttings data (€) • Measurements from core data (€€€€)	**Cuttings**: Med. **Core data**: High	There is currently very little data gathered on the thermal expansion coefficient. However, mineralogical measurements from cuttings data can provide estimations. Cuttings data is always gathered during drilling. Therefore, performing estimations of the thermal expansion coefficient using cuttings data has high VoI.
Unconfined Compressive Strength (UCS) (Chapter 4.3.4)	Knowing UCS strength results in better estimations of the rock strength of the reservoir and caprock. Furthermore, the UCS can help in estimating well bore stability	The UCS can be estimated or measured using the following: • Measured using laboratory tests from core data (€€€€)	**Core data**: High.	Projects which have a relatively thin cap may profit from having (in)direct measurements of the UCS. For these projects, core samples may provide high VoI.

5.3 Conclusive remarks on a data gathering program for geothermal projects

Given the results and implications presented in this chapter, a best estimate data gathering program for new geothermal wells can be proposed, which includes the following standard and additional measurements:

- **Measurements within a standard drilling campaign**: Gamma-ray, Litholog, ROP, Caliper, cuttings, , well test, fluid samples and temperature samples.

- **Proposed additional measurements**: Di-pole sonic log (Vp & Vs) (€€), Density log (if nuclear-sourced tools can be used) (€€), 4 arm-caliper log (€€), a well prepared well-test and/or interference test (€€/€€€) (see chapter 4.2.1), XRD whole rock analysis of cuttings (€) and (X)LOT well test (€€).

Using these standard and proposed additional measurement most parameters and especially the parameters with a high impact on the geothermal well performance can be acquired with some degree of certainty (uncertainty reduction: mostly med. to high). This implies that, for most geothermal projects, including (some of) these additional measurements into your data gathering program can often results in better estimations and lower uncertainties regarding thermal output and subsurface risks. Therefore these measurements might prove beneficial for (new) permit applications and/or new wells.

Whilst this best estimate data gathering provides insights into which measurements have the highest VoI, it should be noted that VoI remains very project specific and dependent on the pre-drill data density and uncertainty. This implies that during the pre-drill phase, the project specific uncertainty of each parameter which has a high impact on the well performance should be estimated. During the subsequent drilling phase, it may be wise to focus the data gathering program on the measurements which provide insight in the parameters with high uncertainties.

Acquiring core data for geothermal projects

Data on a lot of parameters can be measured or acquired using core data. Therefore, core data can have really high VoI. Although the actual measurements on core plugs is not very expansive, it should be noted that the coring of a well is very expensive, and seldomly done in the geothermal sector. This implies that, for the smaller geothermal projects or for projects within a relatively well know geological setting, core data may provide a relatively low VoI. However, in complex geological settings, projects positioned in areas with a relatively low data density, or for relatively large geothermal projects, the insights acquired from core data might be really valuable, thereby resulting in core data having high VoI.

Appendix 1: Rock Composition

The rock composition can provide information on the type of reservoir (e.g. sandstone), the depositional environment and sedimentology or give possible indications on rock properties. During drilling, mud-loggers often provide descriptions of the rock composition and mineralogy (see for example the litholog available on nlog.nl). The rock composition is very difficult to upscale mathematically. However, upscaling can be done qualitatively. For example, different reservoir facies can be identified from core and cutting data and the reservoir can be "upscaled" to different zones (e.g. Weissliegend and Rotliegend).

The rock composition can be measured and or estimated using the following data and methodologies:

- Core plugs and core slabs
    - Thin section petrography
    - XRD analysis
    - (electron) microscopy (EDS/EDX, Microprobe)
    - Visual inspection
- Estimated from log data (e.g. electrofacies Ursem 2018[46])
- Lithologs (EOWR)
- From cuttings/cavings
    - (electron) microscopy (EDS/EDX, Microprobe)
    - Visual inspection

[46] Ursem, 2018. Relating Main Buntsandstein paleo-environments to present-day porosities in the West Netherlands Basin (Master's thesis Utrecht University)

Appendix 2: Fluid properties

Measurements

Using different techniques the fluid properties of reservoir rocks can be measured on fluid samples taken in a well of drill stem test. These include, fluid salinity, fluid temperature, fluid viscosity or the presence of hydrocarbons. Alternatively, these properties can be calculated using log data, reservoir properties or subsurface conditions.

Calculate Fluid Salinity (Brine)

The fluid salinity can for example be estimated using the Crain (1974)[47] methodology:

$$S = \frac{40000}{(T_{\circ F}/\mathrm{RW}_{\mathrm{FT}}^{1.14})}$$

$$\mathrm{RW}_{\mathrm{FT}} = \frac{\varphi^{m} \cdot \mathrm{RES}_{\mathrm{deep}}}{a}$$

Where:

- S = Water salinity (ppm (NaCl equivalent))
- $T_{\circ F}$ = Formation temperature in degrees Fahrenheit
- $\mathrm{RW}_{\mathrm{FT}}$ = the water resistivity at the formation temperature (ohm-m)
- φ = the porosity log (-)
- $\mathrm{RES}_{\mathrm{deep}}$ = the deep resistivity log (ohm-m)
- a = tortuosity exponent (-) (can be measured from core data or estimated from literature)
- m = cementation exponent (-) (can be measured from core data or estimated from literature)

See for example the following quote from Crain's petrophysical handbook for estimates of the tortuosity and cementation exponents:

"Recommended Parameters:

For carbonates a = 1.00 m = 2.00, n= 2.00 (Archi Equation as first published)

For sandstone a = 0.62, m =2.15, n= 2.00 (Humble Equation)

a = 0.81, m = 2.00, n=2.00 (Tixier Equation – simplified version of Humble Equation)

Note: n is often lower tan 2.0

For quick analysis use carbonate values. Values for local situations should be developed from special core data. Results will always be better if good local data is used instead of traditional values, such as those given above.

Asquith (1980, page 67)[48] quoted other authors, giving values for a and m, with n=2.0, showing the wide range of possible values:

Average sands $a = 1.45\ m = 1.54$

[47] Crain's Petrophysical Handbook by E. R. (Ross) Crain, P.Eng., online at www.spec2000.net, 2025

[48] Asquith, G.B. (1980) Log analysis by Microcomputer. The Petroleum Publishing Company, Tulsa

Shaly sands	$a = 1.65\ m = 1.33$
Calcereous sands	$a = 1.45\ m = 1.70$
Carbonates	$a = 0.85\ m = 2.14$
Pliocene sands S.Cal	$a = 2.45\ m = 1.08$
Miocen LA/TX	$a = 1.97\ m = 1.29$
Clean granular	$a = 1.00\ m = 2.05 - PHIe"$

Calculate Fluid density (Brine)

Apart from being measured, fluid densities can also be calculated from the (estimated) salinity, (estimated) fluid pressure and (estimated) fluid temperature. Here, you can for example use the empirical relations from Batzle and Wang 1992[49]:

$$\rho_{fw} = 1 + 10^{-6}\,(-80T - 3.3T^2 + 0.00175T^3 + 489P - 2TP + 0.016T^2P - 1.3 \cdot 10^{-5}T^3P - 0.333P^2 - 0.002TP^2)$$

$$\rho_b = \rho_{fw} + S\{0.668 + 0.44S + 10^{-6}[300P - 2400PS + T(80 + 3T - 3300S - 13P + 47\,PS)]\}$$

Where:

- ρ_{fw} = the fresh water density (g/cm^3)
- ρ_b = the salt water density (brine) (g/cm^3)
- T = the brine temperature at reservoir level (°C)
- P = the pore pressure at reservoir level (MPa)
- S = the salinity fraction (ppm/1000000)

These equations are also used in DoubletCalc[50].

Calculate Fluid Viscosity (Brine)

The fluid viscosity of the formation water can also be calculated using the relations from Batzle and Wang 1992:

$$\mu = 0.1 + 0.333S + (1.65 + 91.9S^3)\exp\{-[0.42(S^{0.8} - 0.17)^2 + 0.045]T^{0.8}\}$$

Where:

- μ = fluid viscosity (cP)
- S = the salinity fraction (ppm/1000000)
- T = the brine temperature at reservoir level (°C)

This equation are also used in DoubletCalc1D V143. It should be noted that in the beta version of DoubletCalc1D (V15)[51], the Kestin viscosity correlation can also be used.Calculate Water Saturation

[49] Batzle and Wang 1992: Seismic properties of pore fluids, Geophysics

[50] TNO 2012: DoubletCalc 1.4 handleiding

[51] https://www.nlog.nl/en/tools

Using the porosity and resistivity logs, the water saturation of a reservoir can be calculated. A water saturation smaller than 1 can be an indicator that free or residual hydrocarbons are present within the reservoir. The water saturation can for example be calculated using the Archie equation (Archie 1952)[52]:

$$S_w = \left(\frac{aR_w}{R_t \varphi^m}\right)^{\frac{1}{n}}$$

Where:

- S_w = the water saturation
- a = tortuosity exponent (-) (can be measured from core data or estimated from literature)
- m = cementation exponent (-) (can be measured from core data or estimated from literature)
- n = saturation exponent (-) (can be measured from core data or estimated from literature)
- R_w = the water resistivity at the formation temperature (ohm-m)
- R_t = the resistivity log (ohm-m)
- φ = porosity log

Apart from the Archie equation, other models such as indonesian or simandoux can also be used. The type of model chosen depends on the type of reservoir.

For more information see: https://wiki.aapg.org/Well_log_analysis_for_reservoir_characterization

[52] Archie 1952: Classification of carbonate reservoir rocks and petrophysical considerations, AAPG Bulletin

Appendix 3: Rock Density

Measurements

Bulk, dry or grain density can be measured in the lab on plugs cuttings/cavings. If measurements are not well possible when there are no samples available of enough size, then values can be estimated from mineralogy (e.g. from cuttings).

Bulk (log) density

- Bulk density is most commonly measured with a density wireline tool in a well. The density is based on the reduction in gamma ray flux between a radioactive source and a detector due to Compton scattering. The service companies will do all the necessary calculations and corrections (e.g. mud infiltration) to obtain the bulk density.
  The measured values will be influenced by hole quality (e.g. break-outs) and therefore the results need to be quality checked versus other tools such caliper or image logs.
- Sonic logs can be used using an empirical Vp to Rho relationship such as summarized in Brocher (2005)[53] For sediments two curves are included in this paper:
  - The Nafe–Drake curve, published graphically in Ludwig et al. (1970), but re-fitted by Brocher (2005) to
    $\rho(g/cm^3) = 1.6612 \cdot V_p - 0.42721 \cdot {V_p}^2 + 0.0671 \cdot {V_p}^3 - 0.0043 \cdot {V_p}^4 + 0.000106 \cdot {V_p}^5$
    the unit of V_p in this equation is km/sec. This equation is fitted for V_p between 1.5 to 8.5 km/sec.
  - Gardner (1974)[54] derived a relationship for sedimentary rocks with V_p between 1.5 to 6.1 km/sec.
    $$\rho(g/cm^3) = 1.74 \cdot {V_p}^{0.25}$$
    Gardner's equation produces densities that are 0.1 g/cm^3 or less higher than the Nafe–Drake curve, but deviates significantly from the Nafe–Drake curve for V_p less than 2 km/sec.

Grain density

- Grain densities can be measured from core data
- Grain densities can be estimated (extrapolated) from core data from other representative wells

[53] Brocher (2005), Empirical Relations between Elastic Wavespeeds and Density in the Earth's Crust. Bulletin of the Seismological Society of America, Vol. 95, No. 6, pp. 2081–2092, December 2005, doi: 10.1785/0120050077

[54] Gardner et al (1974) Formation velocity and density – The diagnostic basics for stratigraphic traps

Appendix 4: Porosity

Measurement and correction

Porosity measurements are preferably done on the same plugs as the permeability measurements are done to obtain the best poro-perm relationship. Core porosity measurements are done at surface conditions. Therefore, the acquired porosities need to be corrected to the pressure at the in-situ depth (TVDm). See for example Evans et al., (1994)[55] which assumes a correction value between 0.87 – 0.91.

Log scale total porosity

Porosity can for example be derived with neutron porosity or NMR tools in combination with a gamma-ray log and a caliper log. Neutron porosity actually measures the hydrogen atoms in the formation, these include the hydrogen atoms in the clay minerals which are not part of the porosity you actually want to use in further analyses. Therefore, the gamma ray log is used to estimate shale and clay content to be able to correct for the clay-bound water, and the caliper log is used to correct for hole quality because break- and wash-outs will influence the log readings.

In absence of those tools, bulk density (ρ_b) can also be used to estimate porosity by assuming grain (ρ_m) and fluid (ρ_{fl}) density.

$$\varphi_D = \frac{(\rho_m - \rho_b)}{(\rho_m - \rho_{fl})}$$

The calculated density can also be combined with a neutron porosity log in order calculate the neutron-density porosity. This method is preferred over using a single log for calculating the porosity. The is equations are as follows:

$$\varphi_{ND} = \sqrt{\frac{\varphi_D^2 + \varphi_N^2}{2}} \text{ (gas bearing)}$$

$$\varphi_{ND} = \frac{\varphi_D + \varphi_N}{2} \left(\frac{\text{water}}{\text{oil}} \text{bearing}\right)$$

Further it is possible to estimate porosity from sonic log slowness (Δt_{log}) assuming the travel time through the rock matrix (Δt_m) and formation fluids (Δt_{fl}).

$$\varphi_{DT} = \frac{(\Delta t_{log} - \Delta t_m)}{(\Delta t_{fl} - \Delta t_m)}$$

However, there are also other approaches available such as the Raymer Hunt equations (Raymer et al. 1980).

$$\varphi_{DT} = C \times \left(1 - \frac{\Delta t_m}{\Delta t_{log}}\right)$$

Where C is an empirical constant (0.624-0.7). Note this equation is an empirical relationship through experimental data points which often works, but has no real physical basis.

[55] Evans et al., 1994: Improved Methods For Correcting Core Porosity To Reservoir Conditions. The Log Analyst 35 (03).

Effective porosity

The effective porosity is a measure of the connected pores which contribute to the permeability of the reservoir (Figure 12). The total porosity can be converted to an effective porosity using different formulas, for example:

$$\varphi_e = \varphi_t - (V_{shale} \cdot \varphi_{shale})$$

Where, φ_e is the effective porosity, φ_t is the total porosity, V_{shale} is the shale volume and φ_{shale} is the shale porosity. The shale porosity (φ_{shale}) can be calculated from the sonic log. The shale volume V_{shale} can be estimated using gamma-ray (GR) or spontaneous potential (SP) logs.

Effective porosities can be used to calculate the log scale permeability. Lastly, check the calculated effective porosity log against the available core data (if applicable) and check whether the results line up. If not, possible correction need to be made to the petrophysical analysis and porosity calculation.

For more information see: https://wiki.aapg.org/Well_log_analysis_for_reservoir_characterization

Upscaling

The porosity log can be upscaled to a single value for a formation using the arithmetic mean. This would lead to a similar total pore volume for the log as for the “single parameter” reservoir. However, it is very likely the porosity distribution will be bi-modal with low porosities for the clay rich formations, and higher porosities for the sandstones formations. Therefore, during upscaling, cutt-off values are commonly used such that only adequate sands are Incorporated (e.g. shale volume < 0.4 and effective porosity > 0.06). See chapter 4 for more information on upscaling of the porosity.

Appendix 5: Permeability

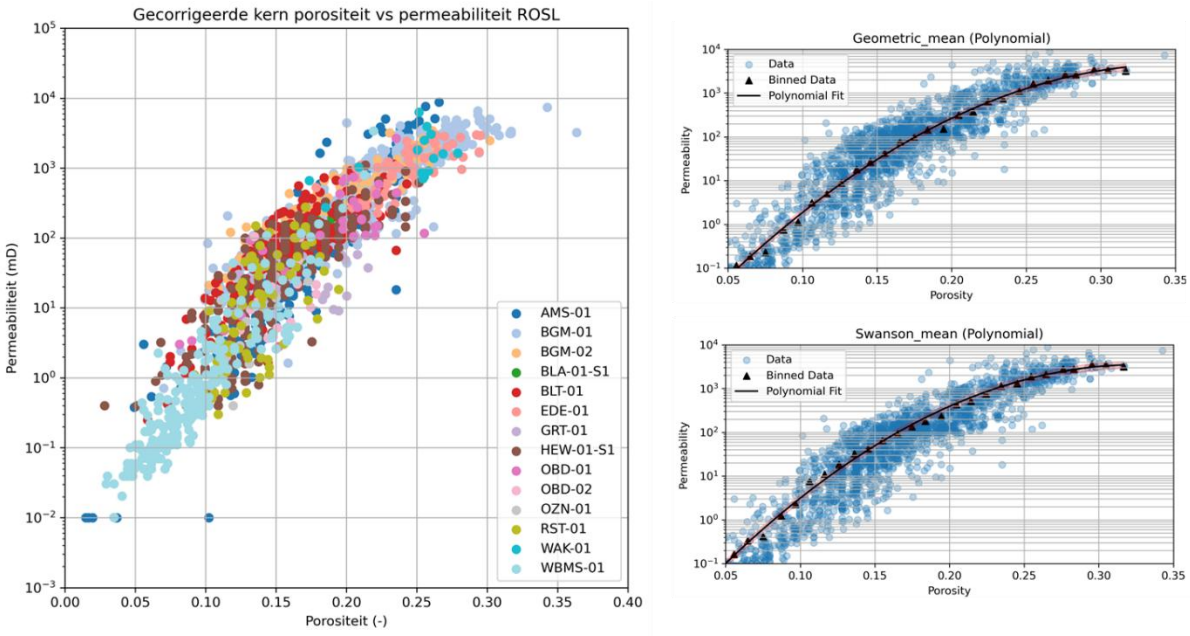
Measurement and correction

Permeability measurements are ideally done using the same plugs which were used for the porosity measurements. Most permeability measurements show the air permeability. These values need to be corrected such that they represent the brine permeability. This can for example be done using the Juhasz correction (Juhazs, 1986)[56]:

- If $K_{air} > 660$ mD:
  - $K_{brine} = K_{air} (\phi_e/\phi_t)^3$
- If 160 mD < K_{air} < 660 mD:
  - $K_{brine} = 0.28\ k_{air}^{1.194} (\phi_e/\phi_t)^{3.045}$
- If $K_{air} < 160$ mD:
  - $K_{brine} = A\ K_{air}^{B} (\phi_e/\phi_t)^{C}$
- Where:
  - $A = 4.14\ \sigma^{-0.39}$
  - $B = 0.8\ \sigma^{0.058}$
  - $C = 2.04\ \sigma^{0.058}$
  - $\phi_e = \phi_t - V_{shale} * \phi_{shale}$
  - σ = effective uniaxial stress at in situ conditions (psi) (Sv – Pore pressure)

Porosity vs permeability relationships

From corrected and representative core plug porosity and permeability measurements, a porosity vs permeability relationship can be acquired for the targeted reservoir layer (see figure). This relationship can subsequently be used for converting effective porosity log data into permeability log data.



[56] Juhasz I. 1986: Conversion of routine air-permeability data into stress brine-permeability data. Tenth European Formation Evaluation Symposium.

Different models/relationships can be used to fit cross-plotted porosity vs permeability data, for example:

- Polynomial fit (e.g. 2nd order: $k_h = 10^{a\varphi_e^2 + b\varphi_e + c}$)
- Exponential fit ($k_h = a \exp^{b\varphi_e}$)
- Logarithmic fit ($k_h = 10^{a \log(\varphi_e) + b}$)
- Power law fit ($k_h = a\, \varphi_e^b$)

Where, a, b and c are constants depending on the statistical fit.

Note: Depending on the dataset, porosity vs permeability relationships may contain large uncertainties. Sufficient filtering of the used data may help in reducing these uncertainties. Nonetheless, uncertainties within the porosity vs permeability relationship should include in the subsequent upscaling steps.

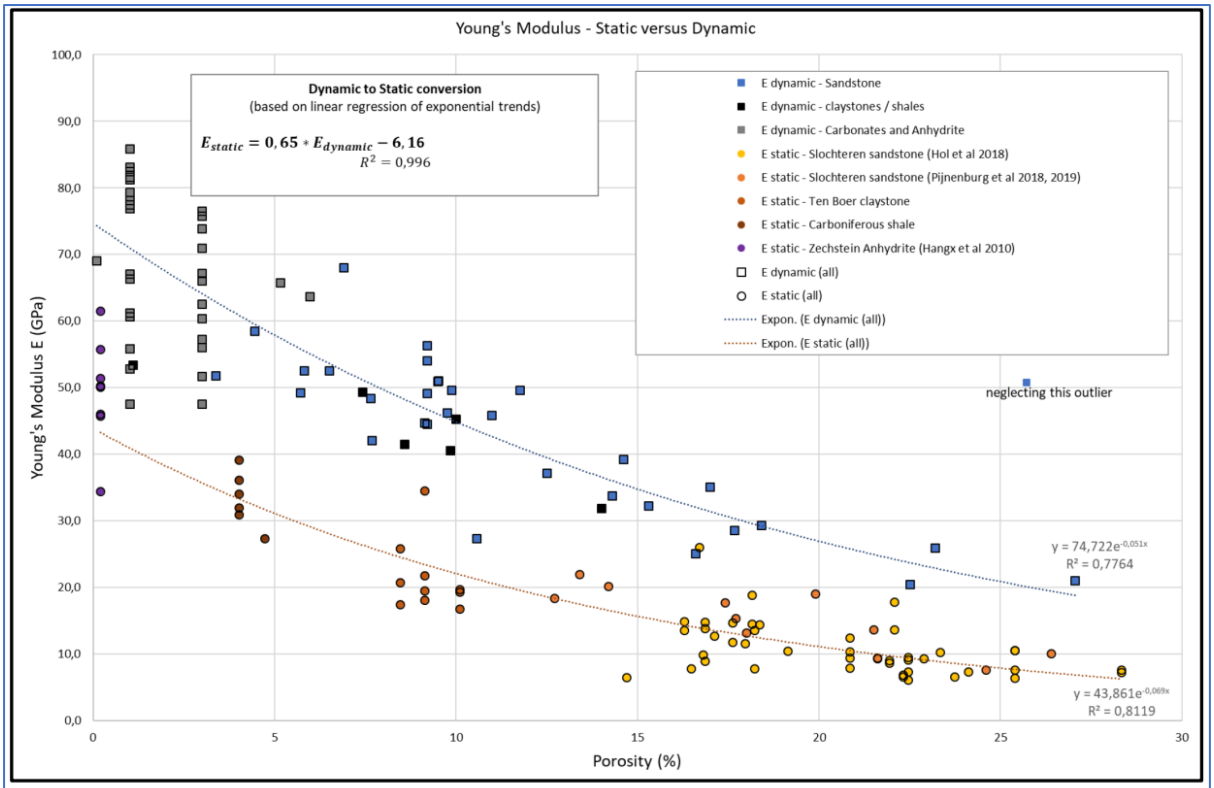
Appendix 6: Young's Modulus

Below is a list of published empirical relationships to convert the dynamic Young's modulus to the static Young's modulus. Please note that these relationships are lithology and case specific and should always be used with care.

DHAIS (2021)

TNO (2021)[57] presents a E_{dyn} to E_{stat} relationship in their report on the update of the Deterministic hazard analyses for induced seismicity (DHAIS) which was developed to assess the probability of earthquakes in the small gas fields in the Netherlands.

$E_{stat} = 0.65 * E_{dyn} - 6.16$ (R^2=0.996)



Figuur D-2 Dynamische Young's modulus E_d uit put analyse (vierkanten) uit TNO, in druk en statische waarden E_s voor de Young's modulus (rondjes) uit literatuur (Hol et al, 2018.; Pijnenburg et al., 2018; 2019 en Hangx et al., 2010) uitgezet tegen porositeit. Empirische relatie tussen E_d en E_s komt uit de lineaire regressie van de trendlijnen van porositeit versus E_d en E_s (blauwe en oranje lijn respectievelijk). In verschillende kleuren staat het type lithologie aangegeven.

Figure 15: E_{static} and E_{dyn} data as collected by TNO for the DHAIS update study.

[57] TNO-rapport 2021 R10977 Deterministische hazard analyse voor geïnduceerde seismiciteit (DHAIS), actualisatie 2021. tno2021_r10977_jr_rapport_dhais_18022022_redacted.pdf

Asef & Farrokhrouz (2017)

Asef & Farrokhrouz (2017). Collected a large amount of published relationships for the Edyn to Estat conversion. Below their main tables with equations.

Table 5: Table 1 from Asef & Farrokhrouz (2017). Sugested equation for prediction of Static Young's modulus

No.	Equation	Unit	R^2	Rock type	Reference
2	$E_{stat} = 1.26 * E_{dyn} - 29.5$	GPa	0.82	Igneous and metamorphic rocks	King (1983)
3	$E_{stat} = 0.74 * E_{dyn} - 0.82$	GPa	0.84	Different Rock types	Eissa and Kazi (1988)
4	$E_{stat} = 1.05 * E_{dyn} - 3.16$	GPa	0.99	Sedimentary rocks	Christaras et al. (1994)
5	$E_{stat} = 0.83 * E_{dyn}$	GPa	-	Concrete	Neville (1995)
6	$E_{stat} = 1.25 * E_{dyn} - 19$	GPa	-	Structural design	CP110 (1972)
7	$E_{stat} = 0.2807 * E_{dyn}$	GPa	0.60	Sedimentary rocks	Brautigam et al. (1998)
8	$E_{stat} = 0.8069 * E_{dyn} - 29.5$	GPa	0.92	Composite Resin	Helvatjoglu et al. (2006)
9	$E_{stat} = 0.7707 * E_{dyn} - 5854$	MPa	0.96	Different Rock types	Mokovciakova and Pandula (2003)
10	$E_{stat} = e^{0.0477 * E_{dyn}}$	GPa	0.72	Different Rock types	Fahimifar and Soroush (2003)
11	$E_{dyn} = 0.5087 * E_{stat} - 6 * 10^6$	psi	0.60	Sandstone	Al-Tahini (2003)

They also combined literature data to derive a dynamic to static relationship which includes porosity (φ); $E_{stat} = E_{dyn}(1 - \varphi) - 3\ln(\varphi)$

Brotons et al. (2016).

Brotons et al (2016)[58] also collected a list of E_{dyn} to E_{stat} conversion relationships for different lithologies.

Eq.	Reference	Relationship	R^2	E_{dyn} (GPa)	Rock type
3	King (1983)	$E_{stat} = 1.26 * E_{dyn} - 29.5$	0.82	40-120	Igneous and metamorphic
4	Vanheerden (1987)	$E_{stat} = a * (E_{dyn})^b \quad a[0.097 - 0.152] \quad b[1.485 - 1.388]$	-	20-135	Sandstone-granite
5	Eissa and Kazi (1988)	$E_{stat} = 0.74 * E_{dyn} - 0.82$	0.70	5-130	All types
6	Eissa and Kazi (1988)	$\log_{10} E_{stat} = 0.77 * \log_{10}(\rho_{bulk} E_{dyn}) + 0.02$	0.92	5-130	All types
7	Christaras et al. (1994)	$E_{stat} = 1.05 * E_{dyn} - 3.16$	0.99	25-110	All types
8	Lacy (1997)	$E_{stat} = 0.018 * {E_{dyn}}^2 + 0.422 * E_{dyn}$			Sedimentary
9	Nur & Wang (1999)	$E_{stat} = 1.153 * E_{dyn} - 15.2$			E_{st}>15 GPa
10	Horsrud (2001)	$E_{stat} = 0.076 * {V_p}^{3.23}$			Shale
11	Martinez-Martinez et al. (2012)	$E_{stat} = \frac{E_{dyn}}{3.8{\alpha_s}^{-0.68}}$		5-50	Limestone-marble
12	Brotons et al (2014)	$E_{stat} = 0.867 * E_{dyn} - 2.085$	0.96	5-30	Calcarenite
13	Brotons et al (2014)	$\log_{10} E_{stat} = 1.28 * \log_{10}(\rho_{bulk} E_{dyn}) - 4.71$	0.97	5-30	Calcarenite
14	Najibi et al. (2015)	$E_{stat} = 0.014 * {E_{dyn}}^{1.96}$	0.87	13-74	Limestone
15	Najibi et al. (2015)	$E_{stat} = 0.169 * {V_p}^{3.324}$	0.90	13-74	Limestone

[58] Brotons, V., Tomás, R., Ivorra, S. et al. (2016) Improved correlation between the static and dynamic elastic modulus of different types of rocks. Mater Struct 49, 3021–3037. https://doi.org/10.1617/s11527-015-0702-7

Brotons et al. propose three new equations with increasing complexity and number of necessary input parameters.

Eq	Relationship	R^2	SSE
20	$E_{stat} = 11.531 * {\rho_{bulk}}^{-0.457} * {E_{dyn}}^{1.251}$	0.993	362.66
21	$E_{stat} = 11.531 * {\rho_{bulk}}^{-2.090} * {E_{dyn}}^{1.287} * \varphi^{-0.116}$	0.994	332.16
22	$E_{stat} = 4.71 \cdot 10^6 * {\rho_{bulk}}^{-2.100} * {E_{dyn}}^{1.232} * \varphi^{-0.129} * UCS^{0.035}$	0.996	190.27

Appendix 7: Unconfined Compressive Strength (UCS)

Estimating UCS

Since direct UCS measurements are not possible with wireline logs, empirical correlations are used to estimate UCS from well log parameters. Some widely used empirical relationships are shown in the table below.

Empirical relations between UCS and other physical properties in sandstone. After Chang, Zoback et al. (2006).

No.	Equation UCS (MPa)	Region Where Developed	General Comments	Reference
1	$0.035\ V_p - 31.5$	Thuringia, Germany	-	Freyburg (1972)
2	$1200\ \exp(-0.036\Delta t)$	Bowen Basin, Australia	Fine-grained, both consolidated and unconsolidated sandstones with wide porosity range	McNally (1987)
3	$1.4138 \times 10^{7}\ \Delta t^{-3}$	Gulf Coast	Weak and unconsolidated sandstones	Unspecified
4	$3.3 \times 10^{-20}\ \rho\ V_p^2\ [(1+\nu)/(1-\nu)]^2(1-2\nu)[1+0.78V_{clay}]$	Gulf Coast	Applicable to sandstones with UCS > 30 MPa	Fjaer, Holt et al. (1992)
5	$1.745\times10^{-9}\ \rho\ V_p^2 - 21$	Cook Inlet, Alaska	Coarse-grained sands and conglomerates	Moos, Zoback et al. (1999)
6	$42.1\ \exp(1.9 \times 10^{-11}\ \rho V_p^2)$	Australia	Consolidated sandstones with $0.05 < \phi < 0.12$ and UCS > 80 MPa	Unspecified
7	$3.87\ \exp(1.14 \times 10^{-10}\ \rho V_p^2)$	Gulf of Mexico	-	Unspecified
8	$46.2\ \exp(0.027\ E)$	-	-	Unspecified
	$2.28+4.1089E$	Worldwide	-	Bradford et al. (1998)
9	$254\ (1 - 2.7\phi)^2$	Sedimentary basins worldwide	Very clean, well-consolidated sandstones with $\phi < 0.30$	Vernik, Bruno et al. (1993)
10	$277\ \exp(-10\phi)$	-	Sandstones with $2 < UCS < 360$ MPa and $0.002 < \phi < 0.33$	Unspecified

Units used: V_p in (m/s), Δt (µs/ft), V_{clay} (fraction), E (MPa), ϕ (fraction)

Appendix 8: Thermal properties

A study conducted by S. Fuchs, N. Balling, and A. Förster, titled "Calculation of Thermal Conductivity, Thermal Diffusivity, and Specific Heat Capacity of Sedimentary Rocks Using Petrophysical Well Logs", and published in Geophysical Journal International (2015), presents a Table, which contains the best-fitting prediction equations for thermal rock properties using various combinations of well-log predictor variables. These equations were derived through statistical regression analysis, allowing for the estimation of thermal conductivity (TC), thermal diffusivity (TD), and specific heat capacity (SHC) based on available well-log data. The selection of these equations was guided by the goal of minimizing prediction errors while ensuring a high level of explained variance.

The table categorizes the equations by rock type, including evaporites, carbonates, and clastic rocks, each with different predictor variable configurations. The performance of these equations was assessed using artificial validation sets and subsurface data, with metrics such as mean error, standard deviation, and root mean square error (RMS) used to evaluate their accuracy.

The equations listed in Table 3 are integral to geothermal and subsurface thermal property analysis, enabling indirect estimation of rock thermal properties where direct measurements are unavailable. The statistical methodology applied ensures that users can select the most appropriate equation for their specific dataset, balancing prediction accuracy with the availability of well-log variables.

Table 3. Best-fitting prediction equations of thermal rock properties for variable number of predictor variables (well logs).

Parameter	Rock group	No. of predictor variables	#	Prediction equations* [W/(mK)]	Error calculation: Artificial validation set R^2 [per cent]	Artificial validation set Mean [per cent]	Artificial validation set SD [per cent]	Subsurface data set Mean [per cent]	Subsurface data set SD [per cent]	Subsurface data set Rms [per cent]
Thermal conductivity	Evaporites	1	A2	$\lambda = 5.34 - 8.14\,\phi_N$	74%	18.0%	14.5%			
		2	A5	$\lambda = 10.73 - 2.22\,\rho_b - 9.21\,\phi_N$	90%	11.4%	11.0%	no data available		
		3	A12	$\lambda = 14.4 - 3.16\,\rho_b - 8.97\,\phi_N - 0.0063\Delta T$	92%	11.2%	9.7%			
		4	A15	$\lambda = 14.32 - 3.15\,\rho_b - 8.93\,\phi_N + 0.005U - 0.0063\Delta T$	92%	11.2%	9.8%			
	Carbonates	1	A17	$\lambda = 3.92 - 5.11\,\phi_N$	59%	13.6%	10.4%			
		2	A30	$\lambda = 5.84 - 0.0063\Delta T - 1.48V_{sh}$	77%	9.8%	7.2%			
		3	A35	$\lambda = -4.37 + 4.18\,\rho_b - 0.3\,U - 1.45V_{sh}$	91%	6.4%	4.9%	no data available		
		4	A44	$\lambda = 0.33 + 2.73\,\rho_b - 0.28\,U - 0.0056\Delta T - 1.54V_{sh}$	93%	5.4%	4.5%			
		5	A46	$\lambda = 1.15 + 2.59\,\rho_b + 1.08\,\phi_N - 0.28\,U - 0.0083\Delta T - 1.66V_{sh}$	94%	5.2%	4.6%			
	Clastics	1	A48	$\lambda = 3.41 - 4.83\,\phi_N$	51%	15.4%	11.2%	18.9%	11.1%	21.9%
		2	A58	$\lambda = 4.17 - 3.89\,\rho_b - 1.78V_{sh}$	76%	11.0%	8.8%	16.7%	10.2%	19.6%
		3	A67	$\lambda = 3.66 - 5.13\,\phi_N + 0.0029\Delta T - 1.70V_{sh}$	76%	11.0%	8.7%	15.8%	9.7%	18.6%
		4	A74	$\lambda = -1.55 + 1.39\,\rho_b - 6.81\,\phi_N + 0.0115\Delta T - 1.53V_{sh}$	79%	10.4%	8.1%	15.2%	10.8%	18.6%
		5	A77	$\lambda = -3.6 + 2.42\,\rho_b - 5.84\,\phi_N - 0.1\,U - 0.0113\Delta T - 1.32V_{sh}$	80%	10.2%	8.1%	15.6%	11.5%	19.4%
Thermal diffusivity	Evaporites	1	B2	$\lambda = 2.49 - 4.35\,\phi_N$	73%	25.2%	27.9%			
		2	B5	$\lambda = 4.94 - 1.01\,\rho_b - 4.84\,\phi_N$	84%	21.8%	23.5%	no data available		
		3	B12	$\lambda = 7.83 - 1.75\,\rho_b - 4.65\,\phi_N - 0.0050\Delta T$	87%	19.6%	19.5%			
		4	B15	$\lambda = 6.86 - 1.70\,\rho_b - 4.16\,\phi_N + 0.065U - 0.0046\Delta T$	88%	19.0%	19.6%			
	Carbonates	1	B17	$\lambda = 1.83 - 2.95\,\phi_N$	77%	12.4%	9.2%			
		2	B30	$\lambda = 2.88 - 0.0063\Delta T - 0.44V_{sh}$	81%	10.9%	7.8%			
		3	B40	$\lambda = 4.02 - 0.092\,U - 0.0080\Delta T - 0.57V_{sh}$	91%	7.9%	6.9%	no data available		
		4	B44	$\lambda = 2.12 + 0.65\,\rho_b - 0.113\,U - 0.0061\Delta T - 0.52V_{sh}$	92%	7.1%	6.4%			
		5	B46	$\lambda = 1.59 + 0.57\,\rho_b - 0.70\phi_N - 0.113\,U - 0.0043\Delta T - 0.45V_{sh}$	92%	7.1%	6.2%			
	Clastics	1	B48	$\lambda = 1.69 - 3.09\,\phi_N$	67%	15.7%	11.3%			
		2	B58	$\lambda = 1.95 - 2.77\,\phi_N - 0.60V_{sh}$	77%	14.0%	10.9%	no data available		
		3	B66	$\lambda = 2.06 - 2.86\,\phi_N - 0.016U - 0.55V_{sh}$	77%	13.9%	10.9%			
		4	B72	$\lambda = -2.62 + 1.65\,\rho_b - 3.32\,\phi_N - 0.116U + 0.0049\Delta T$	77%	13.8%	10.4%			
		5	B77	$\lambda = -0.79 + 1.10\,\rho_b - 2.55\phi_N - 0.08\,U + 0.002\Delta T - 0.38V_{sh}$	79%	13.3%	10.4%			
Specific heat capacity	Evaporites	1	C4	$\lambda = 54.08 + 5.19\Delta T$	69%	13.0%	9.9%			
		2	C10	$\lambda = 991.1 - 73.54\,U + 4.37\Delta T$	87%	6.9%	7.1%	no data available		
		3	C14	$\lambda = 640.4 + 580.3\phi_N - 44.69\,U + 4.07\Delta T$	92%	6.1%	4.9%			
		4	C15	$\lambda = -231.7 + 245.2\,\rho_b + 585.8\phi_N - 42.88\,U + 5.23\Delta T$	93%	6.0%	4.5%			
	Carbonates	1	C19	$\lambda = -376.7 + 6.75\Delta T$	92%	5.9%	5.0%			
		2	C30	$\lambda = -316.7 + 7.14\Delta T - 312.8V_{sh}$	97%	3.5%	3.0%			
		3	C39	$\lambda = 60.69 + 1186\phi_N + 4.63\Delta T - -422.5V_{sh}$	99%	2.3%	2.0%	no data available		
		4	C43	$\lambda = 403.8 - 98.0\,\rho_b + 1253\phi_N + 4.15\Delta T - 439.9V_{sh}$	99%	2.3%	1.9%			
		5	C46	$\lambda = 584 - 194.4\,\rho_b + 1250\phi_N + 10.93\,U + 4.03\Delta T - 435.9V_{sh}$	99%	2.2%	1.8%			
	Clastics	1	C50	$\lambda = -592 + 7.25\Delta T$	96%	4.3%	4.0%			
		2	C61	$\lambda = -517.5 + 7.38\Delta T - 196.3V_{sh}$	98%	3.3%	3.1%			
		3	C67	$\lambda = 59.3 + 1536\phi_N + 3.99\Delta T - 302.1V_{sh}$	99%	1.8%	1.6%	no data available		
		4	C74	$\lambda = 891.3 - 221.4\,\rho_b + 1804\phi_N + 2.62\Delta T - 329.5V_{sh}$	100%	1.3%	1.1%			
		5	C77	$\lambda = 814.6 - 182.9\,\rho_b + 1841\phi_N - 3.62\,U + 2.61\Delta T - 321.8V_{sh}$	100%	1.3%	1.1%			

Note: *A complete overview of all equations can be found in the Appendices A (TC), B (TD) and C (SHC), respectively.

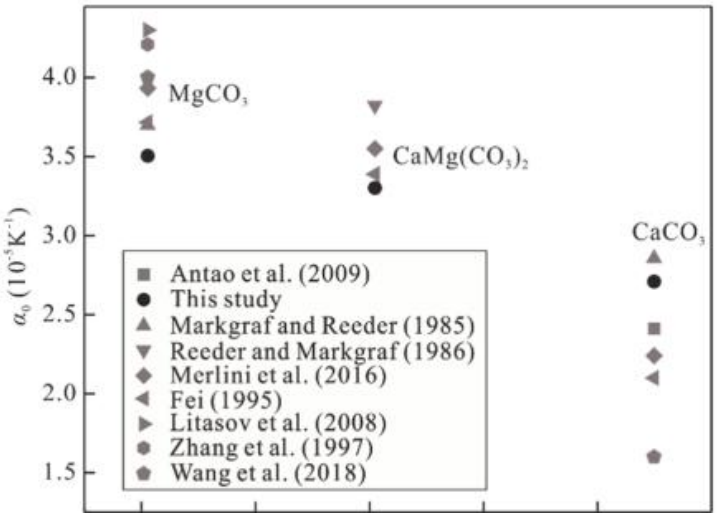
bulk density: ρb (g/cm³), natural gamma-ray: γ (API), sonic interval transit time: ΔT (us/m), neutron porosity: ϕN (fraction), photoelectric absorption index: U (barns/cm³), the volume fraction of shale Vsh (fraction).

Common Minerals and Their Thermal Expansion Coefficients (USGS[1] and Skinner[2,] Dixon[3], 1993), from 20°C to 200°C

Mineral	Composition	Volumetric Thermal Expansion Coefficient (α, in 10^{-5} °C^{-1})
Quartz	SiO_2	3.4 - 5.0 [1,2]
Feldspar	$KAlSi_3O_8$ - $NaAlSi_3O_8$ - $CaAl_2Si_2O_8$	1.0 - 2.2 [1,2]
Calcite	$CaCO_3$	2.0 – 3.0 (see figure below)
Dolomite	$CaMg(CO_3)_2$	3.2 – 3.7 (see figure below)
Clay Minerals	(Kaolinite, Illite)	2.2 – 3.4 [3]
Hematite	Fe_2O_3	3.1 [1]
Halite	NaCl	13.8[1]

Water	T being the temperature in °C, considering constant pressure	$13.9 + 0.61*T^3$

Xiang et al. (2019) published the figure given below. This figure gives the thermal expansion coefficient for Calcite, Dolomite and Magnesite of different studies.



Discontinuities at faults, joints and fractures, foliation and preferred grain orientations, and chemical oxidation and weathering zones are even more prevalent in rock in place, so calculated expansions may be too high when applied to large rock masses.