Annual Monitoring Report

YEAR 2 – January 2021

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Deep GEOTHERMAL IWG
SUPPORT UNIT

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Contents

Introduction

This document represents the second Annual monitoring report, outlining the reported data in 2020. The first report was published in June 2020. It highlighted the key performance indicators (KPIs) established by the IWG for the year 2019. These KPIs are updated every year. EGEC is in charge of overseeing the monitoring of KPIs that were established in the report D6.5. The SU-DG-IWG partners, together with the members of the IWG, evaluate and monitor the learning curve of the different geothermal technologies through reference assets and plants. Therefore, the second monitoring report is related to the reference plants, assets and to the 2019 value as a starting point in terms of costs.

A geothermal heat plant typically needs 5 years to become operational. For electricity, it takes between 6 to 8 years. Considering the above-mentioned timeline, this report is not able to present a full costs comparison between 2019 and 2020.

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Status	**Under Investigation**		**Under Development**				**In Operation**		
Prefeasibility	Services								
Exploration			Exploration & test drilling						
Resource development					Drilling				

In these circumstances, the **main objective is to establish new mechanisms to monitor the RD&I activities** set by the Deep Geothermal Implementation Plan and start the monitoring process. The first mechanism proposed in this report is to make a comparison of the costs in a specific country - the Netherlands.

Secondly, the report presents a series of case studies for presenting the main innovative demonstration projects of 2020 and their potential impacts.

The third instrument is to update the perspectives for the execution of the implementation plan on Deep Geothermal.

The impacts of RD&I projects are defined by quantified smart performance indicators referred as reference plants and assets. The final objective of the data analysis presented in this report is to support and facilitate the work of the IWG by providing a wider in this report is to understand the current trends in RD&I and to adopt corrective implementation measures if needed.

MONITORING BASELINE

The DG-IWG decided to have as baseline the date of endorsement of the Implementation Plan by the SET Plan Steering Committee – **24 January 2018**.
The first costs data correspond to the year 2019. These were reported in D6.5 - the report on reference plants and assests.

Key Performance Indicators

The reference assets are used to assess progress against the targets of the implementation plan of the SET-Plan's action on deep geothermal energy, which is one of a series of technologies that have been identified in two actions whose purpose is to position Europe as "No. 1 in Renewables". Those actions are:
(1) to sustain technological leadership by developing highly performant renewable technologies and their integration in the EU's energy system and
(2) to reduce the cost of key technologies.

The Deep Geothermal Implementation Plan has 8 research and innovation activities, as well as 2 activities on non-technical barriers and enablers that serve to address the targets of the Declaration of Intent.

The indicators refer to both: geothermal power and/or heat plants and key assets.
Six plants are considered: three for power production (including one on EGS), and three plants for heat supply (including one combined heat & power system):

- 20 MW_e high temperature plant (Flash turbine)
- 10 MW_e medium temperature plant (Binary turbine)
- 5 MW_e electric EGS plant (or thermal EGS plant with a capacity of 25 MW_{th})
- 10 MW_{th} heating plant
- 10 MW_{th} heating plant assisted with large heat pumps
- 5 MW_e and 20 MW_{th} CHP plant

A series of assets are presented in the first report. The following reports will not only update the costs data, but also add new assets that will become relevant by technological development.

REFERENCE PLANTS

The choice of reference plants was defined to specifically address **the challenges highlighted in the Implementation Plan's target,** namely to *"Reduce production costs of geothermal energy (including from unconventional resources, EGS, and/or from hybrid solutions which couple geothermal with other renewable energy sources) to below 10 €ct/kWhe for electricity and 5 €ct/kWh$_{th}$ for heat by 2025".*[1]

For each plant category, the reference plant has been taken from the costs of plants in operation. The source is often from a basket of plants in a developed area, for example:

- 20 MW$_e$ high temperature plant (Flash turbine): example of some plants installed in **Tuscany, Italy**
- 10 MW$_e$ medium temperature plant (Binary turbine): extrapolation from the current plants (3-5 MWe) installed in **Bavaria, Germany**
- 5 MW$_e$ electric EGS plant (or thermal EGS plant): extrapolation from the current plants (1-3 Mwe, 24 MWth) installed in **Alsace, France**
- 10 MW$_{th}$ heating plant: example of some plants installed in **Paris region Ile-de-france, France**
- 10 MW$_{th}$ heating plant assisted with large heat pumps: example of some plants installed in **France and in the Netherlands**
- 5 MW$_e$ and 20 MW$_{th}$ CHP plant: example of some plants installed in **Bavaria, Germany**

The costs of geothermal plants depend notably upon economies of scale. The levelized cost of electricity decreases with an increase in installed plant capacity. In general, economies of scale allow both, unit capital cost (in Euros/kW installed) and unit operating and maintenance cost (in Euros/kWh produced) to decline with increased installed capacity.

The power plant construction includes the following steps:

1. power plant equipments: for example the costs for a 10 MWe medium temperature plant (Binary turbine) is between €15 - 25 million;
2. power plant installation and infrastructure (civil works, connection to grid ect.): in this case it would be around €15 – 20 million;

[1] SET Plan - Declaration of intent on Strategic Targets in the context of an Initiative for Global Leadership in Deep Geothermal Energy, https://setis.ec.europa.eu/system/files/integrated_set-plan/declaration_of_intent_geoth_0.pdf

2019 costs

Plants	Capital Costs	Production Costs	Clarifications
20 MW_e high temperature plant (Flash turbine)	€33-62 million in total	38/52 €/MWh_e[2]	€1.65-3.1 million/ MW_e Power plant construction: turnkey costs for Utilities in Italy and Iceland
10 MW_e medium temperature plant (Binary turbine)	€42-57 million in total	140-180 €/MWh_e	€4.2-5.7 million/ MW_e Costs will vary according to the increased amount for power plant construction and installation.
5 MW electric EGS plant (or thermal 25 MW_{th})	€35-50 million in total	Not available	€7-10 million/ MW_e 1. power plant equipment: €10 – 15 million 2. power plant installation and infrastructure (civil works, connection to grid ect.): € 10 – 15 million
10 MW_{th} heating plant	€13-20 million in total	15 to 55 €/MWh[3]	€1.3-2 million/ MW_{th}
10 MW_{th} heating plant assisted with heat pumps	€16.5-24 million in total	15 to 55 €/MWh	€1.65-2.4 million/ MW_{th}
5 MW_e and 20 MW_{th} CHP plant	€18-25 million in total		Combined heat & power costs: 1. power plant equipment: €10 – 15 million 2. power plant installation and infrastructure (civil works, connection to grid ect.): € 10 – 15 million

[2] International Renewable Energy Agency, *Geothermal Power Technology Brief (2017),* https://www.irena.org/publications/2017/Aug/Geothermal-power-Technology-brief#:~:text=August%202017&text=Geothermal%20power%20is%20generated%20from,of%20solar%20and%20wind%20power.
[3] ADEME, *Costs of Renewables and recovered heat in France (2020*), https://www.ademe.fr/cost-of-renewable-and-recovered-energy-in-france

REFERENCE ASSETS

For the purposes of the development of KPIs for the Deep Geothermal Implementation Plan (the 8 research and innovation activities), **"assets" are defined as any activity that has the potential to help deliver the targets of the Deep Geothermal Declaration of Intent and specifically - the cost targets.**
These activities have economic and commercial value and hence are characterized as "assets".

2020 costs (updates)			
Assets	Capital Costs	Comments	
Average costs for identifying a resource	€350,000 and €1,000,000	costs of exploratory drilling is excluded	While many of the assets that constitute value of exploration techniques are low cost, the costs for 2D & 3D seismic surveys and sophisticated modelling tools may be substantial.
Cost estimates for resource exploration	€1-10 million	for the full exploration phase	
Drilling costs to a depth of 1800 m and rate of penetration (hole-making) of 5-10 m per hour	€4 million per well	for a typical heat plant	
Downhole pumps: ESP	€180,000 - €300,000	Investment costs for selecting and installing an ESP	
Yearly operational costs	€60,000 - €100,000	without including the	

		electricity costs for driving the pump.	
Piping and controls for steam gathering	€80,000 - 200,000	steam gathering system of a high temperature flash system can exceed €300/kWe once installed	
Heat exchanger	€130,000 – 150,000	For a typical heat plant most expensive positions are manufacturing (welding, machining, assembling…) and the acquisition of tubes and sheet plates	
Large Heat Pumps of 4 MW_{th}	€3.5 - 4 million		
Transfer station of a 1 MW_e power plant	€80,000 - €85,000		
Routing and cable installation	€100-150 per meter		
District heating grid	€1 million/km	On average	

LEARNING CURVE IN 2020

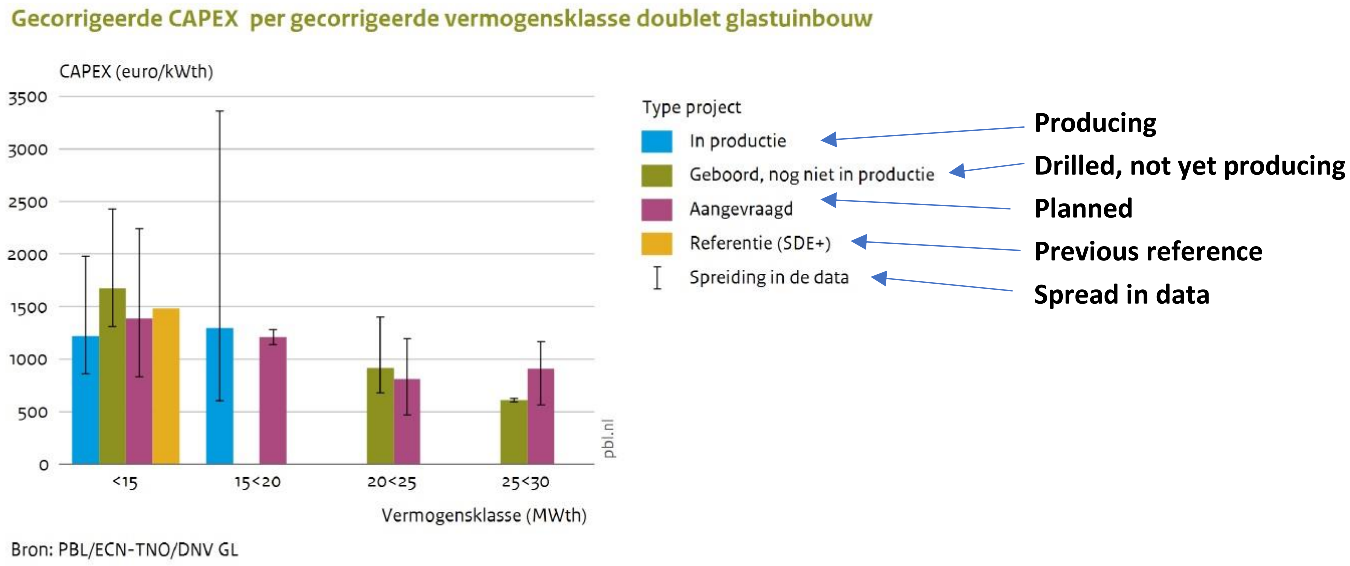
1)Review from the Netherlands

A summary of the cost information from the Dutch funding scheme (SDE+) analysis was presented in February 2020 at the Validation workshop.
SDE+, Stimulation of Sustainable Energy Production is a Feed in premium scheme for sustainable energy in the Netherlands. The Geothermal heat production categories in 2020 are:

- 'Low depth' ≈ 500-1500 m deep
- 'Deep' ≈ 1500-4000 m deep
- 'Ultradeep' > ≈ 4000 m deep

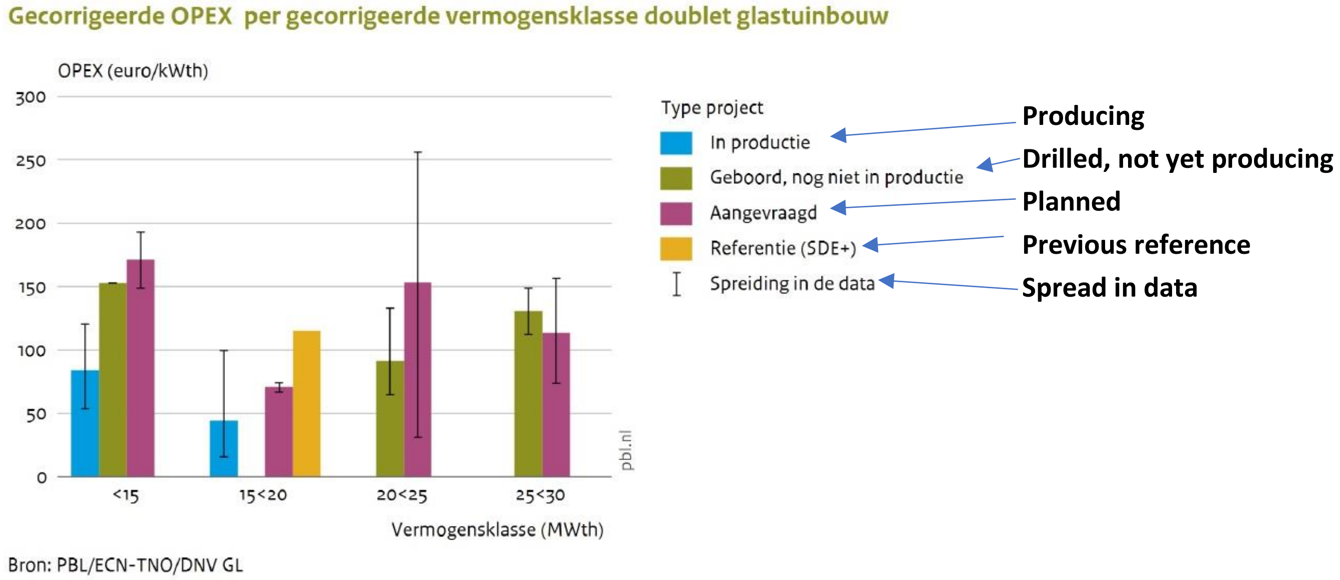
The Base reference cost is adjusted annually by the PBL (Netherlands Environmental Assessment Agency), TNO and DNV-GL. This is based on cost data of actual plants.[4]

CAPEX and OPEX based on 46 projects in the Netherlands:



Figuur 2-3 De gecorrigeerde investeringskosten tegen het maximaal gerealiseerde of gecorrigeerd verwacht vermogen (en maximaal gerealiseerd vermogen voor producerende projecten), onderverdeeld naar reeds producerende en nog niet producerende projecten. Bron: PBL

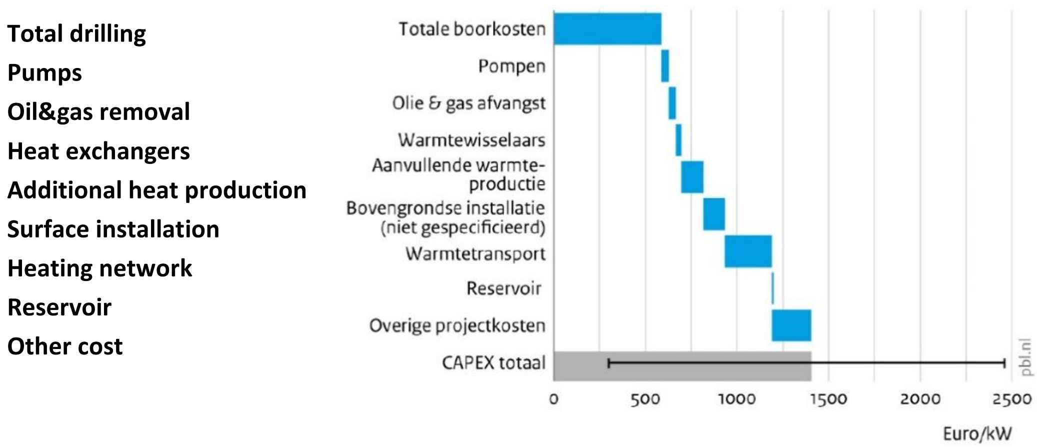
[4] Reference to the SDE+, link to 2020 draft document (in Dutch): https://www.pbl.nl/publicaties/conceptadvies-sde-2020-geothermie



Figuur 2-5 De gecorrigeerde O&M-kosten uitgezet tegen het maximaal gerealiseerde of gecorrigeerd verwacht vermogen, onderverdeeld naar reeds producerende en nog niet producerende projecten. Bron: PBL

Cost structure CAPEX

This is mostly the cases for greenhouse heating projects with geothermal energy. The operational hours are 3800-6000 hours annually. In the Netherlands,the majority of the projects are between 2000-3000m deep, and the geothermal gradient is grossly 30°C/km. For SDE+, the lifetime considered is 15 years.



Figuur 2-4 Weergave van de opbouw van de gemiddelde samenstelling van de investeringskosten over de verschillende geanalyseerde projecten. De spreiding op het totaal geeft inzicht in de totale spreiding over de geanalyseerde projecten. Bron: PBL

Types of the reference plants

Three groups are considered:

- **Low depth geothermal**
- **Deep geothermal**
- **Ultradeep geothermal**

The key differences per group are:

- *Drilling and well technology*
- *Application of heat pump*
- *For ‘Deep’, the capacity is > 20 MW or < 20 MW*
- *Base load vs. non base load*

2) Case studies

The following case studies aim to report the impact on cost reduction or improvement in efficiency for the reference plants.

Case study 1: Geothermal district heating project in Velizy-Villacoublay (France)

Drilling operations started in September 2020 for a new geothermal district heating network in Velizy-Villacoublay (France). The project developed by ENGIE aimed at covering more than 60% of the heat demand for this city.
The project received a financial public support from the Region Ile de France and the ADEME for around €9 million. The expected **GHG emissions savings were about 22 800 tCO2/year.** Moreover, the rig used to drill was running 100% with electrical power (first time in Paris Basins), which means around 5 500 tCO2 saved.

The **innovation part** of this project consisted in the wellbore design in order to deal with a thin geothermal reservoir. The bores’ true depth is around 1600 m, while the total measured depth reached **2400 m thanks to the innovative MultiDrains**. This method has been already used in other sectors, such as oil&gas, but in this case, it was the first time that it has applied for a geothermal energy project.
Instead of the conventional deviated bores with 30° to 40° angle and one single drain, the bores in Velizy-Villacoublay were drilled vertically on 400 meters and were then deviated at 65°- the deviation increased until it has reached the ‘U’ shape. This method allowed to cross twice the Dogger reservoir and increase the exchange surface.

At the top of the deviation, the MultiDrains technology is applied to multiply the captations. The bores architecture is composed of 3 drains, which allows to cross multiple time the reservoir and thus to increase the final productivity in the following steps:

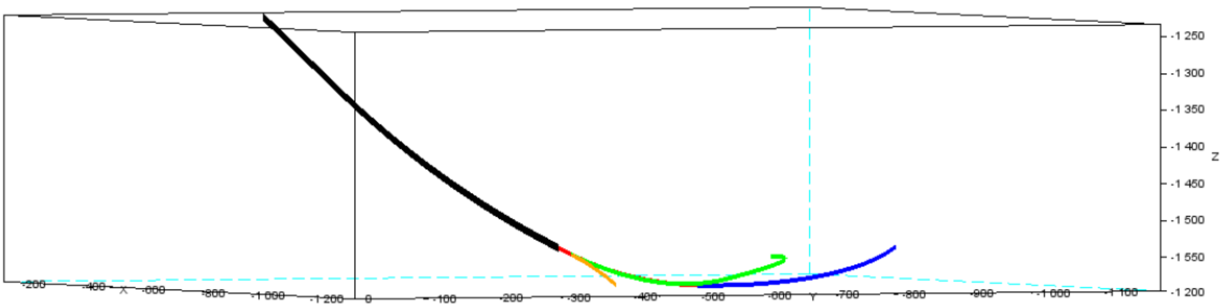
- The first drain taps the reservoir at the end of the first drilling path;

- The second one taps the reservoir a bit further considering an optimised spacing between the first drain and the second drilling path;
- The third one starts from the end of the first path to go down the reservoir vertically and create a sedimentation pocket.

As a result, the flow rate is increased with the objective to reach a minimum of 350 m3/h. Such a new technology, entirely developed by the company ENGIE, has an extra cost of 15% to 20% in comparison with a traditional drilling, but the expected gain on the flow rate reaches around 30. The temperature is around 64°C and the system will be assisted by heat pumps.
Starting in 2021, the geothermal heating systems will provide heat to 12 000 eq. housings and the heat capacity is evaluated at 16 MWth. The **total investment costs are €25 million**. A capital cost of €1.56 million/MWth can be deducted.

In conclusion, this innovative project in Velizy-Villacoublay broadens the field of possibilities for hot sedimentary aquifers exploitation: for a long time many areas that are considered to have low geothermal potential due to the poor reservoir quality, are becoming now the **new potential targets for geothermal district heating.**

Figure 1: Diagram of the innovation with two drains (also called the crow's feet)

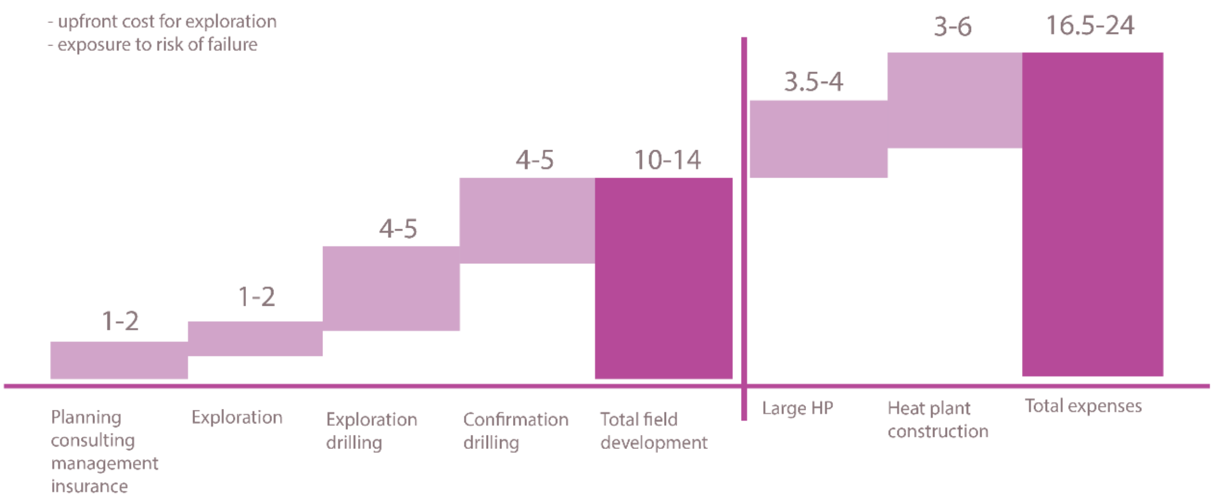


Source: ENGIE, 2020 (https://www.engie-solutions.com/fr/actualites/veligeo-velizy-villacoublay)

Project Véligéo:	• 1 600 m: Wells depth • 2 400 m: Wells length • 16 MW: Capacity
DH in Vélizy:	• 19 km • 140 supply points • 12 000 eq. inhabitants • 130 MW installed capacity

Work Plan:	• July to August 2020: Construction for pre-drilling • August 2020 – Winter 2021: Drilling operations • 2021: DH plant construction and connection to the network • End 2021: Test and start of the operation

Figure 2: Comparison of Cost range for the development of a geothermal DH (doublet) systems, assisted with two large heat pumps, between the reference plant and the plant in Velizy



Case Study 2: St1 project in Espoo (Finland)

St1 is constructing the first industrial-scale geothermal heat plant in Finland with the capacity of up to 40 MW, and one of the world's deepest geothermal well. The most important goal of this pilot project is to develop and test technically and financially profitable solutions for all work phases of the geothermal business concept so that it can be commercialised.

Although geothermal heat is widely used in countries with favourable geographical and geological conditions, this **pilot project by St1 in Otaniemi Espoo is the very first of its kind to take on the world's hardest granite rock material** which is also the oldest dating back 1,8 billion years. In addition to these challenges, the hole being drilled reaches the depths of 6,4 km making it one of **the deepest geothermal hole in the world**. The innovation also contributes to SDGs 7, 9, 11, 13 and 17.

St1 Deep Heat started drilling the wells of the geothermal pilot heat plant in 2016. The pilot project in Espoo was one of the first key projects in renewable energy during the government term to which the Ministry of Employment and the Economy has decided to grant an **investment subsidy**. The Finnish Funding Agency for Innovation Tekes also provided significant support to the scientific research related to the project. The project was chosen as the **best innovation of 2015 in the field of district heating** in a competition that had the goal of finding new technical solutions, services or business models for the field.

Through competitive tendering, St1 Deep Heat chosen Strada Energy, British company specialised in geothermal drilling, as its partner in drilling deep-rock wells. Strada uses patented technology that makes drilling deep into Finland’s hard granite bedrock possible and the company’s mode of operation and cost effectiveness are also a good fit for the Espoo project.

The drill that was used was over 50 metres high and its hoisting capacity was over 400 tonnes. The electricity grid connection of the electrically operated drill was 6.3 MW. The drill was operated in one shift by five persons, part of whom were St1's own staff. It has drilled two over 6 km deep holes, heat wells, between which water will be circulating. Permeability of the bedrock and thus water circulation was enhanced via stimulation, i.e., pumping water with a high pressure to the heat well.

By the end of November 2020, pipeline channels from the wells to the heat plant and connection to the Espoo district heating network have been finalized. Electrical installations are carried out on site and heat exchangers, pumps and auxiliary equipment are being installed inside the building.

2020 developments: Despite the precautionary actions caused by the exceptional COVID19 situation and the technical challenges of the old heat plant building, the work has progressed without interruption. At the same time with the above ground works, a pre-plan for cross hole flow tests of deep geothermal heat wells will be made, which will be commenced in early 2022. The aim of the flow test is to simulate different production conditions with different levels of slow fluid flow test runs.

St1 will sell the output to Fortum, which can cover as much as **10 % of the district heat needs in the Espoo region.**

Figure 3 below represents the comparison of the project against a reference case with traditional geothermal heat and other projects in Finland.

Figure 3: the comparison of the St1 project against a reference case with traditional geothermal heat and other projects in Finland

	Depth	Liquid	Efficiency	Instantaneous power	Continuous power (mm)	Year of Production
Traditional geothermal heat	300m	28% ethanol	3-4	8 - 25 kW	5-7 kW	24-30 MWh
Espoo Koskelo	1.3 km	water	3.5 - 4.5	500 kW	250-300 kW	more than 1000 MWh
Mänttä-Vilppula Kolho	1.5 km	water	3.3 - 4.5	480 kW	(survives use)	1500 MWh
Espoo Otaniemi	6.4 km (x2)	water	9	10,000 - 30,000 kW	10,000 - 30,000 kW	80,000 - 240,000 MWh
Tampere Nekala	6-7km	water	9	6,000 kW	3,000 kW	18,000 MWh

Depth: Depth of a well that is drilled into the ground.

Liquid: Liquid flowing in a thermal well.

Efficiency (COP): How much heat the plant produces compared to electricity consumption. For example, an efficiency of 5 means that the plant generates 5 watts of heat for each watt of electricity it consumes.

Instantaneous power: The power at which the plant can generate heat momentarily.

Continuous power (months): The power at which the plant can produce heat continuously for a month.

Annual production: An estimate or target of the amount of heat generated by the plant during the year.

Case Study 3: Geothermal CHP with lithium in Insheim (GERMANY)

Figure 4 below explain the project phases from project planning in 2007 until the start of the operation in 2012, while Figure 5 illustrates a more technical data on the capital costs.

Figure 4: Project history (source: presentation of Pfalzwerke Geofuture)

February 2007	**Project-planning and preparation HotRock Engineering GmbH**
November 2007	**Start of drilling operations**
June to September 2008	**Successful drilling of first well GTI 1**
November 2008	**Acquisition of project from the geothermal project leader HotRock Engineering GmbH (Karlsruhe) by Pfwalzwerke Geofuture**
January to April 2009	**Successful drilling of second well GTI 2**
2009 - 2010	**Production tests: examination of flow-rate and temperature of the thermal water**
August to October 2010	**Sidetrack drilling in reinjection well GTI 1**
November 13th 2012	**Start of power plant operation**

Figure 5: Technical data of the CHP Insheim (source: presentation of Pfalzwerke Geofuture)

Brine temperature	~ 165°C
Flow rate (max.)	~ 70 l/s
Electric output	
Power (max.)	~ 4,0 MW_{el}
Energy (year)	~ 30.000 MWh_{el}
High availability	~ 8.400 h/a
Thermal energy (option)	
Energy (max.)	~ 10 MW_{th}
On site power demand	~ 25%
Remuneration under the EEG (German Renewable Energy Law)	25 ct/kWh_{el}
Total cost	~ 50 Mio.€

The plant has been in operation for 8 years producing geothermal power. It is currently pumping hot (approximately 165 degrees Celsius), high-flow, **lithium-enriched brine from aquifer depths of >2,980 m to the surface for power generation.**

In 2020, Vulcan Energy Resources Ltd. announced the completion of the maiden Indicated Lithium-Brine Mineral Resource estimate at the Insheim Licence. The resource estimation were completed by APEX Geoscience Ltd. and were conducted in consideration of, and in accordance with JORC (2012). Vulcan has acquired direct access to lithium-enriched brine at the operating Insheim Geothermal Plant and Insheim Exploitation Licence via a binding Memorandum of Understanding with German utility Pfalzwerke geofuture GmbH.
Key highlights of the report shared by Vulcan Energy Resources indicate **a mineral resource of 722,000 t of contained Lithium Carbonate Equivalent (LCE), at the Insheim Licence with a lithium brine grade of 181 mg/l Li.**

Case Study 4: Combined heat and power plant in Milan (Italy)

The Forlanini district in Milan, with about 2,000 apartments, is supplied by a district heating network which is powered by natural gas boilers and a combined heat and power plant (CHP). The plant is located in a basement 8m below ground level and due to the rising of the underground water level it has been subject to flooding several times, which had caused serious damages. This was a critical situation, considering that a CHP with a capacity of 2,4 MW electrical and 2,5 MW heat capacity is installed in the building. In order to prevent these threats, between 50 and 250 m3 /h of groundwater were pumped away into a nearby river, all over the year, with large power consumption.

OCHSNER and its Italian partners developed an **innovative approach to efficiently use the available geothermal energy**. Wells were built for capturing water to be used in a geothermal plant, consisting of 2 heat pumps which are allocated in a new building. The available amount of groundwater and the heat demand are compared by a sophisticated control. According to the calculated value, one or both water-to-water heat pumps are activated. Each heat pump has a heating capacity of more than 800 kW at W10 / W35. A maximum flow temperature of 75°C provides reserves to guarantee a reliable heat supply, even at cold winter days.
The electric power for the screw compressors of the two heat pumps is produced by the CHP unit, which contributes to a short payback period. This project is an innovative approach to an environment-friendly heat supply in Milan.

Case Study 5: Geothermal District Heating in Riehen (Switzerland)

The project consists in the construction of another geothermal heating network in Riehen. The Riehen geothermal system has been reliably delivering heat to the 8,500 residents of Riehen for over 26 years. For the future, Wärmeverbund Riehen AG (WVR) expects continued high heat demand. A second well should therefore tap more naturally available thermal water for heat utilisation. A feasibility study confirmed the potential and good prospects of success for the project. The drilling to pump the thermal water and the construction of the facility will cost around **€20 million**. Starting with 2026, **another 4,000 people can be supplied with climate-friendly energy from Riehens underground.**

The costs are shared between the two shareholders of the WVR, the municipality of Riehen and the Basel energy supplier IWB. The Swiss Federal Office of Energy has pledged funding of € 1.1 million and has announced a further € 5 million. The greater involvement of IWB (the share was recently increased from 27 to 50 percent), makes it easier to finance the project. On the other hand, the WVR can better coordinate the operation of the systems and the growing supply network with IWB. This is particularly advantageous regarding the legally prescribed decarbonisation of the heat supply in the canton of Basel-Stadt. The gradual and partial shutdown of the gas supply is thus optimally coordinated with the growth of the Riehen heating network.

The system will include **two wells:** a production well with a depth at 1.5 Km with a flow rate at 25 l/s, and a reinjection well at 1.2 Km depth. The geothermal brines are at 67°C, and heat is distributed at 70-90°C.

The CAPEX are divided between:

- Prospecting & exploration= ca. €5 million
- Drilling the 2 wells= about €11 million
- Heat plan construction= around €5.3 million

It includes also the replacement investments for:

- Production pumps (every 6 years) = circa €550.000
- Heat plant’s equipments (on a 15 years basis) = about €2.4 million

Capital costs would be around 5%, the lifetime is 50 years and the OPEX are estimated at 2% of the CAPEX. In 2020, the project developer **Wärmeverbund Riehen AG** received a support of €1.1 million from the swiss authority SFOE. This Research project is on ambient refracted p-wave tomography: it may cut cost of prospecting from €2 to 1 million. We assume here a total cost of prospecting for geothermal resource of about €2 million.

The expectations are to double the production, with an additional 13 GWh/year and to cut 6,000 tCO_2/year.
With public approval in November 2020, the planned expansion of the geothermal district heating system in Riehen near Basel, Switzerland can proceed**. The next steps** are seismic surveys to explore the subsurface for “geo2riehen” in summer 2021. These are important to be able to determine the suitability of a later drilling target. If the feasibility of the project is confirmed, **the first of two wells could begin in 2023.**

Case Study 6: Geothermal Heating Systems in Felguera (Spain)

The work on a geothermal district heating network from a geothermal well at Fonzón, in La Felguera (a municipality in Asturia region in the Northern Spain), will conclude in March 2021. The project is being developed by the Hunosa Group.
The works, which began in July 2020, have an awarded budget of €2 million and have the support of the European Union and the Government of the Principality of Asturias, that finance the project. The **total investment consists of €2.3 million, out of which** €1.1 million are awarded through Feder funds.

The project involves the **construction of a heat network** to satisfy the demand for heating and sanitary hot water in buildings around the Pozo Fondón and La Felguera regions, through the geothermal energy use of the pumped mine water. In this first phase, the three shipment of the well will be rehabilitated to house the geothermal generation plant, with a heat output of 1.5 MW thermal energy.

The preparatory works for the installation of a geothermal network will conclude at the beginning of March. Currently, it can boast of being the architect of the largest geothermal complex in Spain, based on the use of mine waters for the air conditioning of various buildings located in the Asturian town of Mieres, which due to its characteristics in terms of flow, temperature and quality, makes them susceptible for this type of use.

The Pozo Barredo geothermal project began its journey 14 years ago to solve the very high economic costs derived from the maintenance of water pumping activities in non-active wells, after different studies carried out by the company concluded that the geothermal exploitation of the mine waters had usable potential. The main production costs were assimilated by the Asturian coal mines within the region that act as a large underground store of water generated by the intense extractive activity developed for more than a century in the interior of the Central Carboniferous Basin of Asturias. During its exploitation, a multitude of infrastructure and start-up work were carried out which, in turn, generated a network of fissures and cavities that increased infiltration and, therefore, the need to pump the flow outside. When exploitation ceases and pumping stops, a natural flood occurs, so that the water passes to occupy the generated spaces, fissures and, finally, the pores. This controlled flooding process takes place until a minimum safety level is reached. To maintain that level, a constant pumping of water is necessary.

First phase: 4 MW of installed thermal energy generation capacity

The first phase of the geothermal project using water from the Barredo Well, carried out by Hunosa Group, **began in 2006** with the start-up of the first two geothermal facilities to supply heat and cold to two buildings: the Vital Álvarez Hospital Buylla (with a surface area of 28,000 m2 and 120 rooms), and the Research building of the University of Oviedo on the Barredo Campus. The estimated annual geothermal energy demand of the Hospital is around 7 million kWh, while that of the Research building exceeds 208,000 kWh.

In 2016, a third facility that supplies geothermal energy was added to the headquarters of the **Fundación Asturiana de la Energía (FAEN)** – an entity dedicated to the promotion and development of research, technological development and training activities related to energy – which occupies a Rehabilitated building in what was the old compressor room of the same well. The estimated annual energy demand of the building is about 72,000 kWh. The three installations, carried out independently, have involved an investment of around **€1.5 million and add up to a total power of 4 MWt**.

Difficulties of exploration: During the development and operation of the three projects mentioned and being aware of the technological advances in generation systems (chillers) that allow to produce at conventional heating temperatures with reasonable COPs and, therefore, the integration of all types of buildings, from Hunosa Group they saw the need to modify their Roadmap for the development of future geothermal projects, since they were encountering various conditioning factors that limited their growth possibilities. On the one hand, the infrastructure in the wells itself makes it technically difficult to add more exchange or impulsion systems to the existing ones. At the same tine, the consumption per distance relationship from potential customers is critical. Added to this is also the difficult installation of chillers in the boiler rooms of existing buildings due to the issues of installed electrical power and physical space, as well as the fact that recirculating water from the mine can cause scale formation problems in the pipeline underground distribution.

The conclusion reached by Hunosa Group was that future projects could not be viewed in a fragmented way for specific clients. To extend the potential of the geothermal resource, the most reasonable, profitable and efficient way was to develop a District Heating (or Heat Network) in which, through a distribution network, future clients could join.

Second phase: 2 MW more capacity

At the end of 2018 the company began the works of the second phase of the **District Heating Pozo Barredo project**, which ended during summer 2019 and whose start-up has been delayed due to the coronavirus health crisis.

The new geothermal installation will allow to power the Polytechnic School of Mieres of the University of Oviedo, the Bernaldo de Quirós Secondary Education Institute and the buildings M-9 and M-10 (totaling 248 homes) of the new Vasco Mayacina residential area, all they also in Mieres, with which the three buildings will achieve significant energy savings.

The new geothermal heat network will have a capacity of 2 MWth, which, added to the 4 MWth of the three previous installations, will represent a total power close to 6 MWth, making it the **first project to be developed as a heat network with a heating system centralised generation with geothermal mine water.**[5]

[5] ThinkGeoenergy, *Turning coal mines in the region of Asturias in Spain to sources of geothermal heating and cooling*, https://www.thinkgeoenergy.com/turning-coal-mines-in-the-region-of-asturias-in-spain-to-sources-of-geothermal-heating-and-cooling/

Perspectives

Further inputs that will be collected in 2021 will be reported in order to have a broader perspective in 2022. **The main objective is to update the six reference plants in a report with a European average and costs ranges coming from plants from all over Europe.**

The deployment of geothermal electricity production in Europe has continued in 2020 following the **positive dynamic of the previous year.**

Regarding reference assets, current defined assets will be updated with new data and new assets may be integrated. The report concludes that thanks to **continuous technological developments, geothermal resources that previously were out of reach will be explored and developed**. The new technological assets will make it technically and economically more feasible. These new assets like storage will be assessed in the upcoming years.

Data will notably be updated with inputs from the Netherlands: SDE+ reference plants OPEX/O&M cost described in the yearly SDE+ advice report by PBL on behalf of the Dutch Ministry[6].

In the upcoming versions of the KPIs report, new aggregated data will be checked against real-life data. For example, the first real-life cost benefit data for Underground Thermal Energy Storage will come from the Dutch UTES Pilot at ECW that is currently realised within the framework of GEOTHERMICA's HEATSTORE project.

In the final version of this reporting (D6.8), data will be reported using the following:

Calculation Metrics: Unit Technical Cost (UTC)

UTC (€/kWh) = Present Value of Total CAPEX (€) + Present value of Total OPEX (€) / Present value of Total Heat & Power Production (kWh).

UTC is the pre-tax, in constant real terms, break-even price

[6] PBL 2020 report, that is used as a basis for the SDE+ feed-in premium system for renewables (electricity and heat) : https://www.pbl.nl/sites/default/files/downloads/pbl-2020-eindadvies-basisbedragen-sde-plus-plus-2020_3526_27-02-2020.pdf . Geothermal reference plants are described in chapter 7, page 60-71.

Technical specifications

From the reference projects and assets, the learning curve will be assessed based on the real examples above, with well-understood cost structure in most common European tectonic settings. Furthermore:

- Possibly to consider a few rarer ones (e.g., hot spot/rifting/subduction zone volcanism/ intraorogenicsetting/ stable continental crust)
- Consider demand side that has most upside and is most relevant for Europe (NECP)
- ✓ Heating projects with a range of depth windows
- ✓ Combined heat and storage projects
- ✓ Combined heat and power projects
- ✓ Power projects
- Define state-of-the-art UTC (€/kWh) and subsets using open spreadsheets and publicly available data
- Hypothesize «if a reference project or reference asset were to be developed and if the developer applied outcomes from R&I projects funded in Europe, then the impact on UTCs (and subsets thereo) is …»
- Pick one DCF model that is open to the public, agree on reference projects and assets, then engage with Pis of research and innovation projects and allow them to comment on the final result using the discounted cash flow (DCF) model.