OPPORTUNITY ANALYSIS

CASCADE INSTITUTE

Deep Geothermal Superpower

Canada's potential for a breakthrough in enhanced geothermal systems

Ian Graham, Ellen Quigley, Scott Janzwood,
and Thomas Homer-Dixon

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Authors

Dr. Ian Graham is a Senior Fellow at the Cascade Institute. A former IT and business consultant, he has held management and leadership positions at the Bank of Montreal, University of Toronto, and small Toronto-based startups, as well as research positions with the National Research Council. He holds a PhD in Physics from McGill University.

Dr. Ellen Quigley is a Senior Fellow at the Cascade Institute. She is the Special Adviser to the Chief Financial Officer (Responsible Investment) at the University of Cambridge and a Senior Research Associate in Climate Risk and Sustainable Finance at the Centre for the Study of Existential Risk (CSER). She holds a PhD in Economics Education from the University of Cambridge.

Dr. Scott Janzwood is the Research Director at the Cascade Institute. His research focuses on how scientists measure and communicate uncertainty and collaborate with policy makers to address emerging risks. He holds a PhD in Global Governance from the University of Waterloo.

Dr. Thomas Homer-Dixon is the Founder and Director of the Cascade Institute. Trained in international relations and conflict theory at the Massachusetts Institute of Technology, his research focuses on threats to global security in the 21st century, including economic instability, climate change, and energy scarcity.

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Contents

Summary 6

1. Introduction 8

   1.1 The net-zero electricity gap 8

   1.2 The deep EGS opportunity 10

2. Background: Geothermal basics 14

   2.1 What is geothermal energy? 14

   2.2 Geology and geophysics of geothermal heat 15

   2.3 Gaining access to heat: Fluids, reservoirs, and heat engines 17

   2.4 Assessing the scale of the geothermal opportunity 20

3. Geothermal project lifecycle 23

   3.1 Introduction 23

   3.2 Planning, exploration, and test drilling 24

   3.3 Production well drilling and well completion 26

   3.4 Reservoir construction 30

   3.5 Power plant construction and power generation 31

4. The deep EGS drilling challenge 36

   4.1 Introduction 36

   4.2 Defining the drilling challenge 37

   4.3 The relationship between geothermal drilling and oil & gas 39

   4.4 Emerging drilling technologies 41

   4.5 Other emerging geothermal technologies 42

   4.6 Canadian context: Technology and research players 43

5. Cost and environmental risk 46

   5.1 CAPEX, OPEX, and LCOE 46

   5.2 Environmental risk 50

6. Financing obstacles and social benefits 59

   6.1 Financing 59

   6.2 Socio-economic benefits 62

   6.3 Additional uses of geothermal energy 63

7. Conclusion: An agenda for R&D, investment, and policy 66
7.1 Audacious goals 66
7.2 Research and commercialization gaps: Recommendations and key questions 66
7.3 Building a deep EGS "Community of Intent" 70
Appendix 1. Measurement of energy and power 71
Appendix 2. Power station characteristics 72
Appendix 3. Estimating accessible geothermal energy 73
Appendix 4. Canadian context: Associations, projects, companies, government agencies, and research groups 77
Appendix 5: Estimating Canadian and global investment in deep, hard rock drilling 82
Appendix 6: Temperatures required to power hard-to-abate sectors 85
Cascade Institute partners 88
Citation 88

Figures

Figure 1. Cross-sectional view of the earth, showing the structural layers. 15
Figure 2. Enhanced geothermal system. 18
Figure 3. A simple taxonomy of reservoir options for geothermal electricity production 19
Figure 4. Geothermal project lifecycle: Risk and cost 24
Figure 5. Simple schematic of a drilling rig and well 27
Figure 6. Casing strings 29
Figure 7. Deep EGS technology gap....38
Figure 8. Deep EGS investment gap 39
Figure 9. CAPEX breakdown for geothermal projects 48
Figure 10. Surface land impact of electricity sources....51

Tables

Table 1. Estimated *recoverable* US geothermal resource base to 10 km by type of geothermal system 21
Table 2. Geothermal vs. petroleum....40
Table 3. Electricity source cost comparison (USD) 47
Table 4. Comparative power densities of selected net-zero energy sources 51
Table 5. Variability of land impact estimates for utility-scale solar PV 52
Table 6. Estimated US geothermal resource base to 10 km depth by category 73
Table 7. Estimated US geothermal resource base to 10 km depth by type of geothermal system....73
Table 8. Estimated *recoverable* US geothermal resource base to 10 km depth by type of geothermal system 74
Table 9. Canadian R&D spending: Oil and gas extraction, contract drilling, and related services....82

Summary

Canada is ideally positioned to be a world leader in geothermal electricity and heat production—a technology that could play a critical role in humanity's zero-carbon energy transition. To realize this opportunity, Canada should launch a national research and development program to massively scale up geothermal power production and R&D over the next 15 years.

A Canadian geothermal breakthrough could fill the country's baseload electricity gap and bring it much closer to meeting its 2050 net-zero carbon commitment. It could also propel Canada to global leadership in exporting geothermal expertise and technology around the world, by leveraging its advantages in drilling technologies, geo-technical expertise, and oil- and gas-field logistics.

This opportunity analysis provides a plain-language introduction to geothermal electricity and heat production. It focuses on **deep enhanced geothermal systems** (or "deep EGS") that create heat-exchange reservoirs in hot, dry rock more than 5 kilometers below Earth's surface. It assesses the deep EGS opportunity, highlights important R&D gaps, and analyzes key technical, financing, and regulatory obstacles.

Our central argument is that Canada can and should become the global leader in deep EGS. But to do so, it must create strong incentives to solve the technology's core R&D challenge: *cost-effective deep drilling through hard (igneous and metamorphic) rock.*

A major program to develop deep EGS in Canada could contribute to national solidarity around climate action, by supporting soon-to-be displaced workers and industries in provinces highly dependent on the oil and gas sectors, without directly competing with those sectors.

Key findings

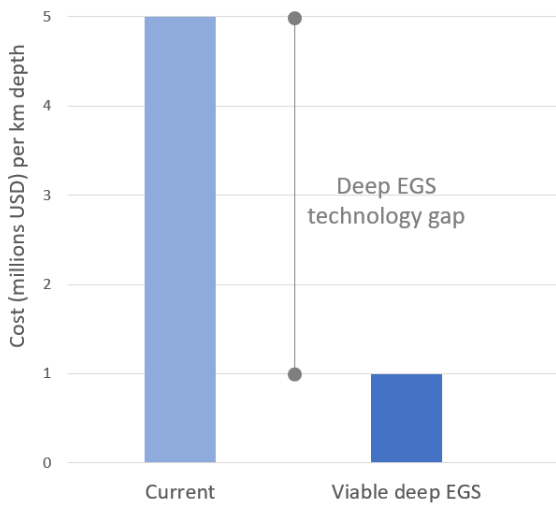
Deep EGS would complement other sources of net-zero electricity while offering several advantages.

	Hydro	Nuclear	Solar	Wind	Biomass	Tidal/Wave	**Deep EGS**
Baseload electricity	✓	✓	✗	✗	✓	✗	✓
Dispatchable electricity	✓	✗	✗	✗	✓	✗	✓
Limited impact on landscape	✗	✓	✗	✗	✗	✓	✓
Near zero-carbon operational emissions	✓	✓	✓	✓	✗	✓	✓
Resilience to climate change impacts?	✗	✓	✗	✗	✗	?	✓
Broad public support	✗	✗	✓	✗	✗	✓	✓

90% **or more of the geothermal opportunity is accessible only with deep EGS.**

In principle deep EGS could be deployed in almost any location and by itself power the global economy.

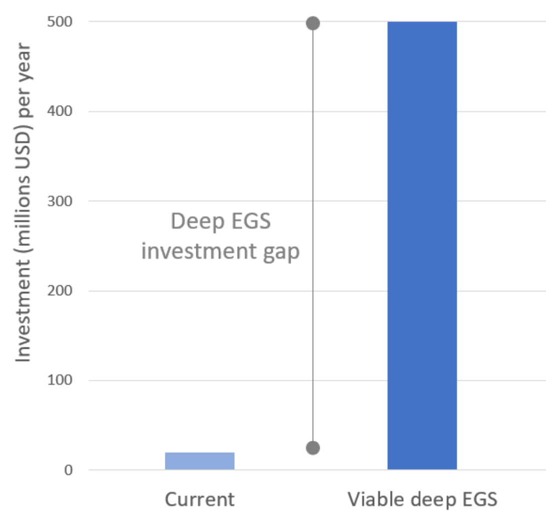
But deep EGS requires transformational advances in drilling technologies to make deep drilling technically and financially feasible.



With existing drilling technologies, it is likely feasible to drill to depths of around **10 km** through hard rock at a cost between **50 and 100 million USD** per well. These costs need to be reduced by **an order of magnitude** (to 5 to 10 million USD) to make deep EGS economically viable in the current energy market.

Emerging technologies—such as percussive, waterjet, and plasma drilling—offer pathways towards cost-competitive drilling through hard rock.

Research and development investment in deep, hard rock drilling totals about **20 million USD per year** worldwide. To achieve economic viability within a reasonable timeframe, investment must grow **by more than an order of magnitude**—to approximately **500 million to 1 billion USD per year**.



Government must take a leadership role on deep EGS financing. The federal government's support of nuclear power development provides a precedent and a model.

1. Introduction

1.1 The net-zero electricity gap

With commitments to achieve net-zero emissions by 2050 and to ramp up carbon pricing in the coming decade, the federal government has signaled Canada is getting serious about transforming its economy to address the climate crisis. But the government's plans lack specifics about the combination of energy sources, technologies, policies, and investments necessary to achieve these drastic emission cuts while meeting rising energy demand.[1] Because Canada lacks an ambitious green industrial strategy, it is falling behind the US, Europe, South Korea, China and other economies in creating the technologies and industries that will form the backbone of a global net-zero economy.[2]

If Canada is to reach its ambitious climate targets and compete in a global net-zero economy, two tasks stand out: (1) developing technologies capable of massively scaling up the country's net-zero electricity production, and (2) exporting these technologies and Canadian energy-system expertise to the rest of the world.

Canada's electricity production is directly responsible for only about nine percent of Canada's emissions, with low- or zero-carbon sources currently dominant.[3] (Alberta, Saskatchewan, Nova Scotia are the only provinces generating a significant amount of their electricity from carbon-intensive sources.[4]) But demand for electricity will soar as key economic functions like heating, transportation, and agri-food production fully electrify. In its recent *Canada Energy Future 2021* report, the Canada Energy Regulator (CER) projects that domestic electricity demand could increase between 69 and 83 percent by 2050, creating large **net-zero electricity gaps** for *all* provinces and territories.[5] According to the Canadian Institute for Climate Choices, electricity generation *capacity* will have to outpace forecasted demand growth, doubling or even tripling by 2050 to account for the variability from higher shares of solar and wind.[6]

The CER report describes six scenarios for net-zero electricity production in 2050—all of which require massive increases in solar- and wind-generated electricity. But this expansion would entail significant land-use and landscape impacts (see Section 5.2). Also, solar and wind technologies provide *intermittent power*; their output depends on weather, season, and time of day. The CER scenarios address the intermittency issue mainly by adding 50 to 60 GW of battery storage by 2050 (a total greater than the combined power output of all fossil fuel and nuclear plants in Canada today). The CER report does acknowledge the enduring need for *baseload power*, which provides a constant and reliable flow of electricity, and for *dispatchable power*, which can be ramped up or down to balance grids and meet fluctuating demand (see Appendix 2).

Today, the two main sources of net-zero baseload electricity in Canada are hydro and nuclear power. (Hydroelectricity is also a dispatchable source of electricity—it can theoretically be turned off or on in minutes—

but nuclear power is not.) To balance the grid, the CER scenarios also include sizeable contributions from conventional natural gas plants (both with and without carbon capture and storage) in Alberta and Saskatchewan, as well as modest increases in hydro and nuclear across Canada. Other studies of Canada's projected electricity mix in 2050 propose a much larger grid-balancing role for nuclear[9] or a balance between battery storage and natural gas.[10] Both nuclear and hydro have significant environmental and political risks[11,12]—
and carbon capture and storage technology is a long way away from delivering on the promise of net-zero electricity from natural gas.[13]

Globally, the net-zero electricity gap is truly enormous. Under a net-zero emissions scenario, the International Energy Agency (IEA) projects that the world's electricity demand will increase more than 150 percent by 2050.[14] In 2020, 38 percent of global electricity came from renewable sources and nuclear; but by 2050 that share will need to jump to 95 percent.[15] While solar and wind are expected to do most of the heavy lifting, every country faces a unique set of supply challenges as well as imperfect solutions to the intermittency and landscape-impact issues.

This analysis therefore presents the case for deep geothermal electricity production—first, as a source of baseload and dispatchable net-zero electricity in Canada and, second, as an opportunity for Canada to become a world leader in exporting deep geothermal expertise and technology internationally. We evaluate the technology's potential (to contribute to a fully decarbonized electricity grid) against other non-fossil-fuel technologies like solar, wind, and hydro; we do not compare it with oil, gas, or coal electricity generation that is coupled with carbon capture and storage.

Projecting electricity demand growth

This opportunity analysis assumes that electricity demand will increase dramatically in the next 30 years—both in Canada and around the world. This assumption is supported by various mainstream energy system models.[7]

But it is important to acknowledge that projecting demand for energy commodities is inherently complex. Electricity demand is fundamentally driven by **human needs**, such as needs for nourishment, safety, and social belonging—which, in turn, shape preferences for **energy services**, such as heating and transportation.

A growth in demand for energy services will likely result in a growth in demand for electricity, but demand for energy services may also be addressed by better efficiency in energy systems or by alternative energy forms (e.g., green hydrogen for industrial processes or direct use of geothermal heat).

Further, commodity demand projections often assume that preferences for energy services in the future will resemble preferences today. But societies may choose to meet their fundamental needs in new, less energy-intensive ways. For example, more people may work from home (or closer to home), reducing commutes and lowering demand for transportation services.

While our core assumption about a high rate of growth in electricity demand is widely held, we acknowledge that preferences for energy services can shift over time and have important implications for electricity demand.[8]

The growing number of large geothermal systems around the world indicates that the technology can provide reliable, affordable electricity, as a vital complement to output from solar, wind, and hydro. But unlike the latter technologies, which all depend on relatively benign and predictable climate patterns, geothermal is less vulnerable to the impacts of climate change. Geothermal also has high power density, meaning that its facilities produce a large amount of energy per square metre of land they occupy or disturb. It therefore has a much smaller landscape footprint than solar arrays, wind farms, and hydro reservoirs producing equivalent power, with potentially far lower impact on critical agricultural and recreational land, biodiversity, and ecosystems.

Deep geothermal offers another advantage to Canada: the technology, when fully developed, will use much of the same intellectual and human capital as the oil and gas industries. Canada's net-zero carbon energy transition necessitates immediate emission reductions in domestic oil and gas production and an almost complete ramp-down of the sector by 2050.[16] Such an economic transition will require the reskilling of tens of thousands of workers. Rather than allowing existing expertise in resource exploration, drilling technology, hydraulic fracturing, and logistics to "die on the vine," deep geothermal electricity production could become an important alternative source of high-quality jobs and economic opportunities.

1.2 The deep EGS opportunity

So, with all these advantages, why is deep geothermal not a bigger part of the Canadian energy transition story? And why is Canada not pioneering new geothermal technologies and exporting Canadian geothermal expertise around the world?

The main reasons are particularities of Canadian geography and geology. Canada has almost no geothermal resources close to Earth's surface. Such *shallow hydrothermal* resources (containing naturally occurring water or steam) are relatively accessible and economically viable geothermal opportunities, but they tend to cluster along the boundaries of tectonic plates. Deep geothermal resources without naturally occurring water or steam, which *are* located throughout Canada, are more difficult to reach, and can only be exploited using **enhanced geothermal systems (EGS)**.

So, the real question is: why isn't Canada a world leader in *deep EGS*? Answering this question requires we review a series of tightly interconnected technical, financing, social, and political challenges. The main technical challenge is our current inability to drill inexpensively through hard rock to depths of 5 to 10 km quickly and cheaply. Financing deep EGS is impeded by the lack of incentives for investment in early-stage R&D—particularly investment in the development and testing of new drilling technologies. Socially and politically, the greatest obstacle is the prevailing belief that current zero-carbon electricity sources and strategies are sufficient for transforming our energy system and decarbonizing the economy. Many investors and policy makers seem to think that new technologies like deep EGS are a distraction from the core task of scaling up existing technologies.

Through an in-depth exploration of these challenges in the following pages, we reveal a compelling opportunity for Canada to leverage its existing comparative advantages in drilling, exploration, and logistics to fill the net-zero electricity gap in Canada and around the world.

We argue that Canada can and should become the global leader in deep EGS and to do so, it must create strong incentives for solving this technology's core research, development, and demonstration (R&D) challenge: *cost-effective deep drilling through hard (igneous and metamorphic) rock.*

Canada is currently making "bets" on two main technologies to fill its net-zero electricity gap: first, on efficient, high-capacity battery storage for intermittent electricity sources (especially wind and solar); and second, on safe and secure small modular reactors (SMRs). But both bets are confounded by problems.

Even with major advances in battery technology, the increase in wind and solar output required to fill the gap will have enormous landscape impacts. Public resistance to nuclear power—particularly to waste-disposal sites—remains substantial, and this resistance will almost certainly carry over to SMRs. Given these problems and the urgent need to diversify and transition our energy systems, Canada should a make a third bet, we argue, on cost-effective hard-rock drilling for deep EGS.

To be clear, the engineering, technological, financial, and regulatory challenges confronting economically viable deep EGS are formidable. But they are no more formidable than the challenges facing

Deep EGS: The basics

What is an enhanced geothermal system (EGS)?

EGS is a human-made geothermal reservoir in a region of hot rock that otherwise contains little or no natural fluid. It is created by drilling into the region, stimulating the rock to open pre-existing fractures, and then injecting fluid to fill the artificial reservoir. The fluid is heated by the hot rock and then brought to the surface to power turbines, as in a conventional hydrothermal system.

What is "deep" EGS?

Here, we define "deep" EGS as reservoirs created more than 5 kilometers below the Earth's surface. The ultimate goal is to make affordable and commonplace reservoirs 10 or more kilometers deep.

Why "really deep" is really good

Very few places on Earth have "high quality" heat trapped less than 5 kilometers below the Earth's surface—and such places are almost exclusively found in tectonically active zones. But by drilling much deeper, geothermal systems can be placed far away from tectonic plate boundaries, reducing the risk of "induced seismicity" (i.e., earthquakes). By drilling deeper, the range of locations where geothermal systems can be set up increases exponentially.

Deeper also means hotter. Higher temperatures mean that more electricity can be extracted per unit area (i.e., the power density of the installation increases), and should also decrease the risk associated with depleting the rock's heat capacity over time. Extremely high-temperature geothermal systems could also provide direct heat for hard-to-decarbonize high-temperature industrial processes such as cement manufacturing, hydrogen production, and metallurgical processing.

intermittent electricity storage and SMRs. When announcing a 20 million CAD (16 million USD) investment in SMR technology, Canada's then-Minister of Natural Resources, Seamus O'Regan, declared that "the government of Canada [is] ensuring that we have every tool possible in our toolbox to reach net-zero carbon emissions by 2050 and address the existential crisis of climate change."[17] Geothermal is a tool that deserves far more attention than it is currently receiving.

This opportunity analysis is for policymakers, investors, and other stakeholders working to accelerate a *just* net-zero energy transition—one that produces green jobs and opportunities in resource-based communities and harnesses the expertise and entrepreneurship of Canada's energy sector. Section 2 provides background on the geology and geophysics of geothermal energy, the types of geothermal systems, and an overview of the geothermal opportunity in Canada. Section 3 summarizes each stage of the geothermal project lifecycle, while Section 4 focuses on the deep drilling challenge. Section 5 discusses the costs and environmental risks of geothermal and how the technology compares with other zero or near-zero carbon electricity sources. Section 6 proposes a financing pathway for a deep EGS breakthrough in Canada, from the R&D stage to full commercialization, and examines province-specific energy-mix, employment, and skill-set considerations.

Lastly, Section 7 concludes by identifying a set of "audacious goals" for deep EGS in Canada, listing key recommendations and questions, and calling for the development of a "community of intent" that will articulate and execute a Canada-wide agenda for deep EGS R&D policy and investment.

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[4] According to Meadowcroft et al. (*Ibid*), in 2018, Alberta produced 2 percent of its electricity from renewables, Saskatchewan 16 percent, and Nova Scotia 24 percent.

[5] We use data from the Canada Energy Regulator's data set for its *Canada's Energy Future 2021* report. This analysis projects that Canadian electricity demand will increase 41 percent between 2022 (564.6 TWh) and 2050 (796.1 TWh) in its "Evolving Policies Scenario." While we were unable to find electricity demand projections for the "Higher Demand Scenario" for each province or for Canada as a whole, the report states that electricity demand is 15 to 45 percent higher in the Higher Demand Scenario than in the Evolving Policies Scenario, "depending on the province." Therefore, we assumed that electricity demand in the Higher Demand Scenario is *30 percent* higher in 2050 than the Evolving Policies Scenario—which means that electricity demand is projected to increase 83 percent between 2022 (564.6 TWh) and 2050 (1,034.9 TWh) in the Higher Demand Scenario. Similarly, the report states that electricity demand is 10 to 30 percent higher in the NZE Base Scenario than in the Evolving Policies Scenario, "depending on the province." Therefore, we assumed that electricity demand in the NZE Base Scenario is *20 percent* higher in 2050 than the Evolving Policies Scenario—which means that electricity demand is projected to increase 69 percent between 2022 (564.6 TWh) and 2050 (955.3 TWh) in the NZE Base Scenario. See

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[8] We would like to thank Ralph Torrie, Director of Research at Corporate Knights, for explaining the distinction between needs, energy services, and energy commodities—and for encouraging us to explicitly surface our core assumption about electricity demand growth.

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2. Background: Geothermal basics

Key messages:

- There is enough potentially accessible geothermal energy inside the earth to sustainably power the global economy thousands of times over.
- Easy to reach geothermal energy is found in the general neighbourhood of tectonic plate boundaries, which limits “traditional” (i.e., hydrothermal) geothermal stations to a small percentage of Earth’s land surface (< 1 percent).
- Geothermal’s future is in *deep EGS*—artificial geothermal reservoirs created >5 km below the Earth’s surface. This technology would greatly expand the geographical range of accessible geothermal energy.

2.1 What is geothermal energy?

Geothermal energy is heat inside the earth, some of which can be extracted and used as a practical source of energy. Geothermal energy originates from two sources. The first, called primordial heat, is a legacy of the creation of Earth, roughly 4.5 billion years ago. As material collided and merged to form the planet, the kinetic energy from those collisions was converted into heat now trapped inside the earth. The second source is radiogenic heat, continuously produced by the decay of trace amounts of radioactive elements found throughout the planet. Because of its origin, geothermal energy is essentially carbon-free and naturally renewable.

There are several ways to take advantage of geothermal energy. Heat pumps can leverage low-temperature heat in bodies of water or hot rock near Earth’s surface to deliver energy-efficient heating or cooling. On larger scales, geothermal power stations extracting more intense heat from deeper in the earth can deliver high-temperature heat needed for industrial purposes including the generation of renewable, essentially carbon-free electricity.

Generating electricity from geothermal energy is not a new idea. Indeed, the world’s first geothermal power station was built in 1904 in Tuscany, Italy, taking advantage of easy access to natural steam venting out of the ground.[1] Since then, roughly 80 geothermal power plants have been built around the world, delivering in 2019 an installed electrical power capacity of 14 GW worldwide[2]—more than the entire generating capacity of British Columbia and roughly twice the output of the Bruce Nuclear Generating Station (see Appendix 1 for an explanation of how energy and power are measured).

But geothermal makes up only a small portion (0.18 percent in 2018) of the world's total electricity production capacity.[3] Canada currently does not generate any electricity from geothermal, although a number of pilot projects are underway (see Appendix 4).

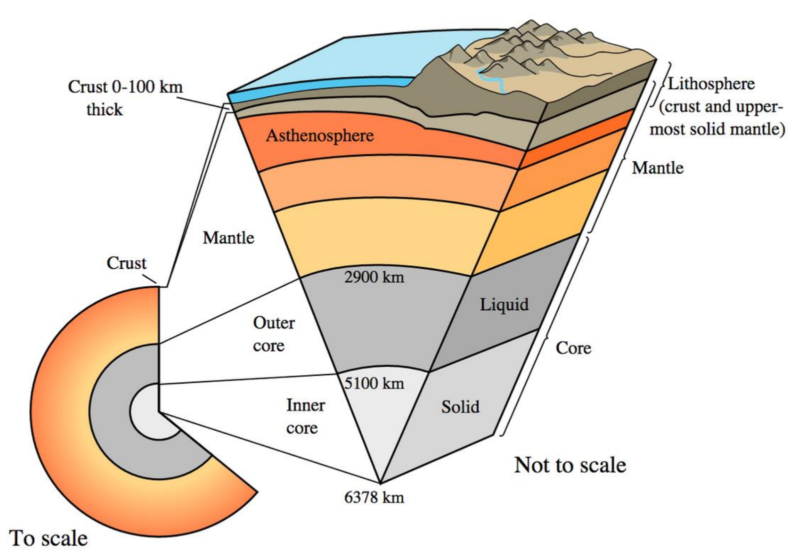
Meanwhile, the potential for geothermal energy is enormous: there is enough deep geothermal energy to satisfy the entire world's current and forecasted electrical and thermal energy needs thousands of times over.[4] (See Appendix 3 for an analysis of accessible geothermal resources in Canada.) With the right technology, geothermal energy can be the foundation of a global net-zero energy system.

2.2 Geology and geophysics of geothermal heat

Earth is a spinning sphere with a radius of approximately 6,400 km, held together and tightly compressed by gravity. Structurally, it is made up of several layers, each with distinct properties. Figure 1 is a conceptual cross-section of the earth showing these layers—from the *crust* at the surface to the two-layer *core* at the center, with the *mantle* (itself made up of four layers) in between.

The crust is the only layer we ever see: the thin layer of solid rock (ranging from 30 to 100 km thick on land, thinner under the oceans) that forms the surface of the earth. The temperature at the top of the crust (the surface temperature of Earth) is governed by Earth's biosphere, with local temperatures varying modestly between roughly -50°C and +50°C depending on the local climate. The temperature at the bottom of the crust ranges from roughly 300°C to 1,000°C, gradually increasing by an average of 35°C/km. But the actual temperature at a given depth varies widely depending on where you drill.

Figure 1. Cross-sectional view of the earth, showing the structural layers.
(Source: *USGS 1999*[5])



Below the crust lies a massive layer of very hot and dense rock known as the mantle, ranging in temperature from roughly 1,000°C at the top to around 4,000°C at the bottom. The bottom layers of the mantle are essentially molten rock, moving slowly under convective flow (hot rock rising, cooled rock falling). This is the mechanism by which heat and energy are slowly transferred from inside the planet towards the surface.

The top layer of the mantle (unimaginatively termed the *upper-most solid mantle*) is made up of dense, very hot (up to 1,000°C) but still mostly solid rock. Collectively, the combination of the upper-most solid mantle and the crust is called the *lithosphere* and is essentially the "solid rock portion" of the planet. Structurally, the lithosphere is made up of 20 large surface regions called *tectonic plates*—enormous solid plates of crust and upper mantle that fit together like a badly planned jigsaw puzzle and define the surface structure of the oceans and continents. These plates sit on top of a layer of the mantle called the *asthenosphere*. The asthenosphere's temperature and pressure are high enough that the rock is soft, semi-molten and quite ductile. As a result, the tectonic plates essentially float on top of the asthenosphere, slowly pushed by the convective motion of the semi-molten rock below.

Some tectonic plates push into each other (at "convergent boundaries"), creating mountain ranges, while others move away from one another (at "divergent boundaries"), providing channels for the upward flow of magma and, occasionally, the creation of massive underwater volcanoes. In other cases, plates slide next to each other at "transform boundaries." Regions near plate boundaries are prone to severe earthquakes since portions of the plates tend to "stick" to each other for a while and then suddenly lurch free. Such zones include the west coast of California and British Columbia. As a result of these dynamics, Earth's crust tends to be thinner near plate boundaries where plumes of very hot, semi-fluid rock from below the lithosphere can heat rock closer to the surface.

For this reason, easily accessible (i.e., not too deep) high-temperature geothermal energy is often found near plate boundaries. Indeed, most current geothermal power stations are found near plate boundaries, such as in California, Indonesia, Iceland, Turkey, New Zealand, Italy, and the Philippines.

Conversely, far from plate boundaries and near the center of tectonic plates (e.g., Canada east of Saskatchewan), the crust tends to be thicker and the temperature gradients lower. Thus while you may only need to drill a few kilometres into the earth to find high temperatures near a plate boundary,[6] you may need to go anywhere from 5 to 12 km into the earth to find similarly high temperatures in the center of a tectonic plate.

For geothermal "prospecting," it is important to have good geological survey data, including estimates of the temperature below the surface as a function of depth. Some national and multinational organizations (US Department of Energy, EuroGeoSurveys, the Geological Survey of Canada) provide access to such information, but geographical coverage tends to be limited.

2.3 Gaining access to heat: Fluids, reservoirs, and heat engines

All geothermal power stations work the same way: they "mine" thermal energy from underground (typically by extracting very hot water or "fluid"[7]), use heat engines (such as steam turbines) to convert thermal energy into mechanical energy, and use that mechanical energy to turn a generator and create electricity. With some stations, the heat itself can be the product if there is a suitable local market.[8]

Geothermal power stations have one key requirement: cost-efficient access to good geothermal heat. "Good" means two things: (1) the fluid can be extracted at sufficiently high temperatures (the hotter the better, ideally >150°C) and (2) the fluid can be extracted at sufficiently high flow rates (typically hundreds or thousands of gallons per minute) since the amount of thermal energy is proportional to the amount of fluid.

Conceptually, there are two classes of geothermal reservoirs that can drive a geothermal power station: reservoirs that exist naturally (called *hydrothermal*) and reservoirs that are created or engineered (called *enhanced geothermal systems* or EGS). In either case, the reservoir is a (natural or created) geological structure that "traps" very hot fluid so it cannot flow away (allowing the fluid to be extracted and reinjected) and is continually heated from below.

Hydrothermal reservoirs

Almost all existing geothermal power stations use hydrothermal reservoirs. Such reservoirs have a natural supply of extremely hot fluid or steam trapped in relatively shallow and easy to reach sedimentary rock layers above very hot rock formations that keep the fluid hot. Regions satisfying these requirements are always found near plate boundaries. Natural reservoirs require a handful of geological conditions. Typically, a hydrothermal reservoir has a "dome" of hard impervious rock (often called a caprock) on top of a layer of permeable sedimentary rock (e.g., sandstone) which serves as an *aquifer* through which fluid can flow. The fluid that flows through the aquifer is heated and rises into the trapped dome.

As in oil and gas extraction, the fluid is reached using wells. The heat energy in the extracted fluid is then converted into electricity by the power plant at the surface. Modern systems use additional wells to re-inject the cooled fluid back into the reservoir, so the plant and reservoir becomes a closed loop system, keeping the reservoir full and avoiding the release of potentially toxic chemicals or dissolved greenhouse gasses from the fluid into the environment.

The geological requirements for hydrothermal reservoirs (hot rock close to the surface, the existence of a "just right" geological formation yielding a natural reservoir, and a local geography that naturally fills the reservoir with rainwater) are extremely rare. For example, in the US, it is estimated that only 0.1 percent of the total potential geothermal resource base is found in hydrothermal reservoirs.[4]

Geological data suggest small regions in British Columbia and Alberta may offer hydrothermal reservoir sites capable of generating a few hundred MW of electrical capacity.[9] However, little exploration work has been done to confirm this estimate or to locate potential sites.

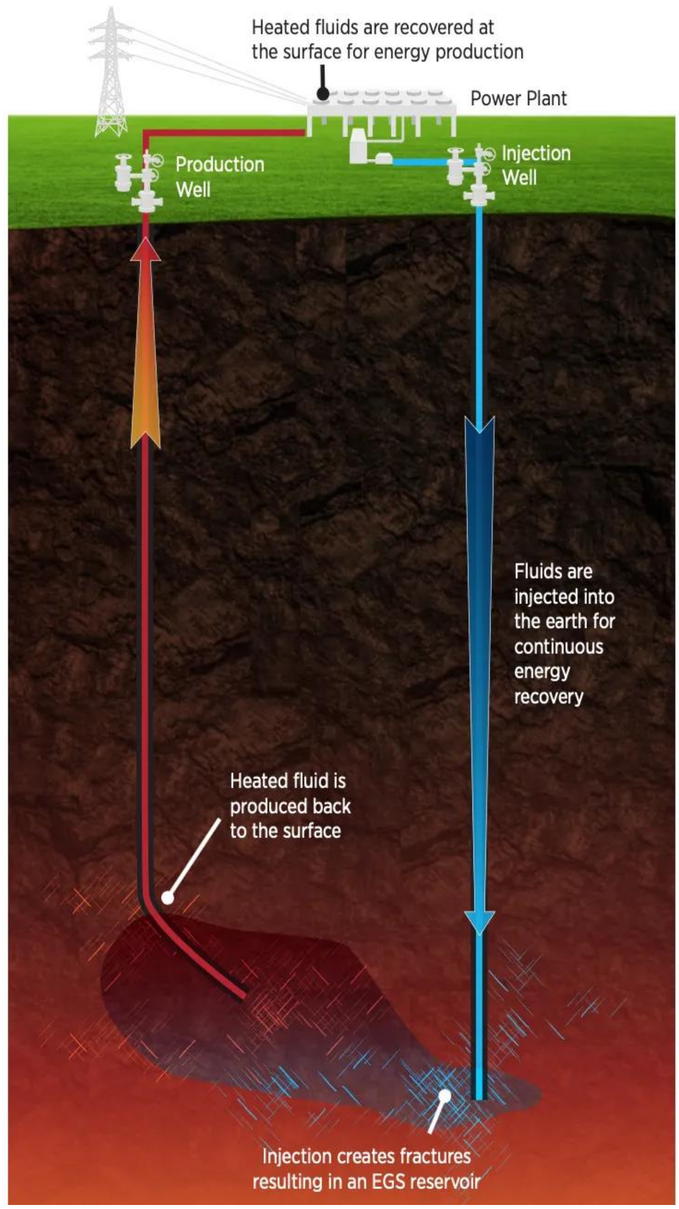
Enhanced geothermal systems

Enhanced geothermal systems (EGS) greatly expand the overall power capacity and geographical range of geothermal since this approach, in principle, makes it possible to create reservoirs almost anywhere. Indeed, if you can drill deep enough (i.e., 10 km or deeper) you can almost always find sufficiently high temperatures. For this reason, EGS is widely seen as the future of geothermal.[10]

In EGS, a geothermal reservoir is created in a region of hot rock that may contain little or no natural fluid and that may even be, in its natural state, impermeable to fluid flow. Given a suitable rock formation, such regions can be "engineered" to create a reservoir by drilling into the region, stimulating the rock to produce fractures allowing fluid to flow, and then injecting fluid to fill this artificial reservoir. Figure 2 illustrates the EGS approach.

There are a wide range of hot rock formations where EGS can work. In some cases, the hot rock is permeable but dry (essentially "hydrothermal but without the hydro"). In other cases, the rock is impermeable and dry because fluid cannot get in or out (sometimes called "hot dry rock", or HDR). Given the right geology, such rock regions can be "enhanced" to create a reservoir by adding fluid and, in the case of HDR, "stimulating" the rock to create pathways so fluid can flow through it.

Figure 2. Enhanced geothermal system.
(Source: *US Department of Energy 2019*[10])



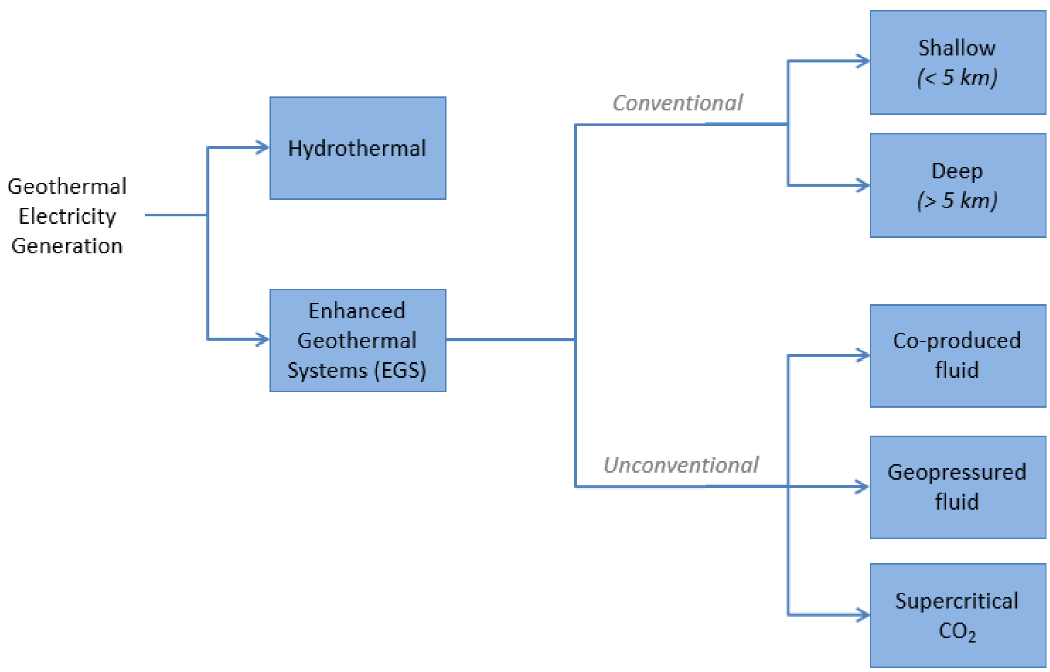
There are several approaches to "enhancing" rock for geothermal power. Figure 3 summarizes these approaches in an overall geothermal taxonomy that divides EGS into two classes: *conventional* and *unconventional*.

Conventional approaches are the fluid-based approaches described above. Unconventional approaches are, essentially, everything else.

The industry tends to differentiate between two types of conventional EGS: (1) *shallow EGS* for reservoirs less than 5 km deep, and (2) *deep EGS* for reservoirs at depths greater than 5 km. This 5 km boundary is somewhat arbitrary and is in part based on the notion that, to our knowledge, no EGS reservoirs have been built deeper than 5 km.[11]

It may be more accurate to name these two classes "soft rock EGS" and "hard rock EGS," since shallow EGS is mostly drilled through softer sedimentary rock similar to that encountered in oil and gas drilling, while deep EGS almost always requires substantial drilling through extremely hard igneous or metamorphic rock. Drilling through sedimentary rock is relatively easy using existing oil and gas drilling technology. Hard rock drilling is not. Deep EGS calls for cutting-edge, untested, or hypothetical new drilling technologies (see Section 4.3).

Figure 3. A simple taxonomy of reservoir options for geothermal electricity production
(Adapted from *Schlumberger Business Consulting 2008*[12])



Indeed, all current EGS projects are "shallow" owing to the cost and difficulty of deep drilling into hard rock. They are also all located near plate boundaries to leverage hot rock near to the surface. Since 1970, there have been roughly 70 shallow EGS projects around the world, most (particularly the earliest ones) conducted to test and refine EGS technology.[13] Of these, around 10 are currently operating as commercial electricity providers. Importantly, the success rate for EGS projects has vastly improved over time as experience from early pilots has translated into practical experience and success.[14] In Canada "shallow" EGS is only viable in parts of Saskatchewan, Alberta, British Columbia, and the Yukon.

More broadly, EGS systems can, in principle, be built essentially anywhere provided you can drill 10 km or more through very hard rock to find sufficient heat. In practice, current challenges and costs associated with hard rock drilling limit EGS to shallow reservoirs, severely restricting where they can be constructed.

There are also three *unconventional* EGS approaches, none of which is currently in use: co-produced water, geopressured water, and supercritical carbon dioxide (Fig. 3). The first two are niche opportunities associated with existing oil producing regions. Meanwhile, supercritical carbon dioxide systems replace the water-based working fluid with carbon dioxide and could, in principle, be used for either shallow or deep EGS.

Co-produced water leverages hot fluid found in existing oil and gas production zones that lie in regions of hot rock. In principle, this hot water can be extracted as a by- or co-product of oil and gas production and used to generate electricity.

Geopressured water can sometimes be found in deep (>4 km) sedimentary basins trapped beneath domes of impermeable sedimentary rock. Such reservoirs can contain water that is both hot and under substantial pressure (often the water also contains large quantities of dissolved natural gas). In principle, useful energy can then be obtained from three sources: the hot water, the extreme pressure of the hot water, and from the natural gas. Such sites have been identified in the northern Gulf of Mexico[15] but, so far, none has been exploited to produce geothermal energy.

Supercritical Carbon Dioxide (CO_2) can be used instead of water as the working fluid for EGS, potentially overcoming some of the corrosion issues associated with conventional EGS and also sequestering large amounts of carbon deep beneath the surface of the earth. This technique is discussed further in Section 4.4.

2.4 Assessing the scale of the geothermal opportunity

At an aggregated level, we can look at the geothermal opportunities offered by each category of geothermal (hydrothermal, shallow EGS and deep EGS) from two perspectives: (1) the estimated amount of power the category can deliver, and (2) its geographical coverage (i.e., the percentage of the land surface area for which the category is feasible).

Table 1 shows an estimate of the recoverable geothermal energy in the US. Similar datasets do not yet exist for Canada. Estimates for other countries or regions will vary according to their unique geology and geography. However, given the range of geography and geology covered by the large land mass of the US, it is a reasonable assumption that the percentage estimates for the United States are of *the same order of magnitude* as those for many other countries, including Canada.

Table 1. Estimated *recoverable* US geothermal resource base to 10 km by type of geothermal system
(see Appendix 3 to see how this table was produced)

Type of geothermal system	Accessibility of the resource	Percentage of land surface area	Potential Electrical Power (GW)	Percentage of Total Power
Hydrothermal	Easy	< 1%	196	0.07%
Shallow EGS[16]	Difficult	< 2% (western part of country)	3,450	1.3%
Deep EGS	Very difficult	~ 90%	262,500	98.6%
2020 US electrical production capacity[17]			1,117	

We can draw two important conclusions from these estimates:

1. By far, the bulk (>90 percent) of the geothermal opportunity lies with deep EGS which is, in principle, accessible from almost all geographic locations and offers essentially limitless electrical power.
2. Shallow EGS offers substantial electrical power but is geographically limited to regions close to a tectonic plate boundary.

There has been no similar assessment for Canada, but we can expect the results to be similar due to the shared geological and geographical properties between the northern United States and southern Canada. Notably, hydrothermal opportunities are likely limited to small regions in British Columbia and Alberta, and shallow EGS to small regions in British Columbia, Alberta, Yukon, and Saskatchewan, and potentially the Northwest Territories (see Appendix 3 for more details). Deep EGS, when feasible, shows promise across much of the country and, in particular, in the heavily populated regions of eastern Canada.

Notes

[1] Unwin, J. (2019). "The oldest geothermal plant in the world." *Power Technology*. 8 October 2019. https://www.power-technology.com/features/oldest-geothermal-plant-larderello/.

[2] International Renewable Energy Agency (IRENA). "Geothermal energy." https://www.irena.org/geothermal (accessed 10 May 2021).

[3] US Energy Information Administration (EIA). "International Electricity capacity." *EIA*. https://www.eia.gov/international/data/world/electricity/electricity-capacity. (accessed May 2021).

[4] See the following report that conservatively estimated the amount of extractable geothermal energy at between 2,000 and 20,000 times the then-annual consumption of all primary energy in the US: Idaho National Laboratory (INL). (2006). *The Future of Geothermal Energy*. Massachusetts Institute of Technology: Cambridge MA. ISBN: 0-615-13438-6. https://energy.mit.edu/wp-content/uploads/2006/11/MITEI-The-Future-of-Geothermal-Energy.pdf.

[5] United States Geological Survey (USGS). (1999). "Cutaway views showing the internal structure of the Earth." *USGS*. https://www.usgs.gov/media/images/cutaway-views-showing-internal-structure-earth-left (public domain).

[6] "Near" can mean many hundreds of kilometers, as the geological impact of plate collisions spread far beyond the geographical centre of the collision zone.

[7] The word "fluid" is preferred over "water" because the water used in geothermal systems is heavily saturated with salts, dissolved minerals and gases.

[8] Geothermal stations can sell heat to nearby companies for heat-intensive industrial processes, such as curing and drying, or to commercial or residential customers for heating. Geothermal power stations can also sell residual or "waste" heat from powering turbines, which has a very low unit cost.

[9] Palmer-Wilson, K., J. Banks, W. Walsh, and B. Robertson. (2018). "Sedimentary basin geothermal favourability mapping and power generation assessments." *Renewable Energy* 127: 1087-1100. https://doi.org/10.1016/j.renene.2018.04.078.

[10] US Department of Energy. (2019). "GeoVision: Harnessing the Heat Beneath Our Feet." *US Department of Energy*. https://www.energy.gov/sites/default/files/2019/06/f63/GeoVision-full-report-opt.pdf.

[11] Other publications use different definitions for shallow and deep EGS, while some use entirely different subcategories for EGS (e.g., EGS located near hydrothermal fields versus EGS that are not located near such fields).

[12] Schlumberger Business Consulting. (2007). "Improving the economics of geothermal development through an oil and gas industry approach." *Schlumberger Business Consulting*. https://www.smu.edu/-/media/Site/Dedman/Academics/Programs/Geothermal-Lab/Documents/Oil-and-Gas-Publications/Schlumberger_Improving_the_Economics_of_Geothermal_Development.pdf.

[13] List of EGS projects around world: https://en.wikipedia.org/wiki/Enhanced_geothermal_system#Summary_of_EGS_projects_around_the_world.

[14] Doughty, C., P. F. Dobson, A. Wall, T. McLing, and C. Weiss. (2018). "GeoVision Analysis Supporting Task Force Report: Exploration." *Lawrence Berkeley National Laboratory*. Report #: LBNL-2001120. Retrieved from https://escholarship.org/uc/item/4v7054cw.

[15] Ganjdanesh, R. and S. A. (2016). "Potential assessment of methane and heat production from geopressured–geothermal aquifers." *Geothermal Energy* 4(16). https://doi.org/10.1186/s40517-016-0058-4.

[16] In Table 1, shallow EGS also includes several potential "unconventional" approaches that leverage existing "hot oil" production formations. See Appendix 3 for details.

[17] US Energy Information Administration (EIA). (2021). "Electricity explained: Electricity generation, capacity, and sales in the United States." *EIA*. https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.

3. Geothermal project lifecycle

Key messages:

- The geothermal project lifecycle unfolds in four broad and often overlapping phases:
  1. planning, exploration, and test drilling;
  2. production well drilling and well completion;
  3. reservoir construction; and,
  4. power plant construction and power generation.
- The biggest R&D gaps are associated with drilling, well completion, and reservoir construction.
- There is a critical lack of high-quality geological data relevant to deep EGS for most of Canada—particularly for the Canadian Shield and eastern Canada. Existing Canadian data tends to focus on shallow resources.
- Improving the exploration success rate and lowering exploration costs require improvements in remote sensing technology, surface geochemistry, and field geophysics—as well as a national agency to facilitate data aggregation and knowledge exchange.

3.1 Introduction

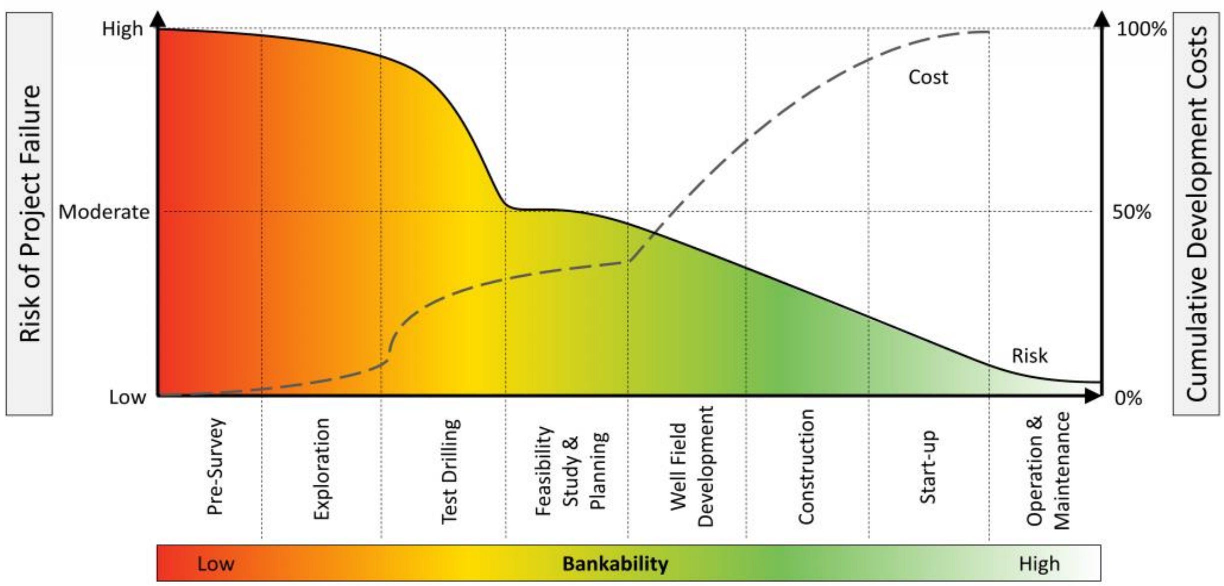
As with other large infrastructure projects, geothermal power stations take a long time to build—often 10 years from inception to operation, and sometimes longer. But geothermal projects often have much higher initial project risk than other energy systems. The balance of cost and risk for geothermal projects is more like that of mineral exploration than of other power generation approaches such as hydroelectricity or nuclear.

Figure 4 illustrates the cost and risk profile of each stage of the geothermal project lifecycle based on experience to date.[1] Note that we repackage the components of the geothermal project lifecycle presented in Figure 4 into four broad and often overlapping phases: planning, exploration, and test drilling; production well drilling and well completion; reservoir construction; and power plant construction and power generation. Half or more of the project risk is concentrated in the initial planning, exploration, and test drilling, which all take place before there is a reasonably high degree of confidence that the project will be completed. Indeed, only roughly 20 percent of geothermal power station projects continue past the test drilling stage, and even then, the risk is still moderately high. High up-front cost and high project risk means elevated financial risk. Therefore, projects tend to be structured to reduce risk as early (and inexpensively) as possible.

This risk profile also means it can make sense (as with oil drilling) to invest in many modestly sized projects as opposed to a small number of larger ones because the aggregate risk of making several smaller "bets" is often lower than placing a single bet on one potentially high-return project. In addition, if one of these projects identifies a potentially large, high-energy geothermal field, that project and power station can be expanded over time, at relatively low risk, since the initial project has essentially "de-risked" the field.

Figure 4. Geothermal project lifecycle: Risk and cost

(*Palmer-Wilson 2017,*[2] *adapted from Gehringer and Loksha 2012*[3])



While Figure 4 maps out these four phases sequentially, they often overlap. Many large existing geothermal power stations have been built out iteratively, with wells and power generation capacity being added over time. Alongside these activities, projects must obtain all appropriate zoning, environmental, regulatory, and other permits to proceed with the work.

3.2 Planning, exploration, and test drilling

Planning and exploration

Geothermal projects begin by identifying candidate sites for reservoirs and power stations. The developer reviews existing geological data (from oil, gas, and mining surveys and from academic researchers and national labs such as the Geological Survey of Canada) to identify regions likely to have the desired heat at accessible depths and the suitable geology for building a reservoir. These data may be supplemented with aerial surveys to measure surface heat flow or to gather geomagnetic data (which measure properties of underground rock). Aerial surveys are an inexpensive way to gather data over a wide geography and can often be performed without formal survey permits. Once candidate regions are identified, the project team applies for formal surveying permits and will commission more detailed surface exploration to examine the geology and surface chemistry (from which one can infer features underground) and potentially perform seismic surveys.

At this point, the developer also starts building relationships with key local stakeholders (e.g., governments, Indigenous communities, landowners, etc.).

Planning and exploration work may include "exploratory" drilling to help further understand local geology. Exploratory drilling is sometimes treated as a separate phase since it often requires additional permits. Exploratory drilling is much simpler and less expensive than test drilling and production well drilling: exploratory holes are much smaller in diameter, not as deep, and not constructed for long term use. But such drilling can be essential for measuring temperature with depth, the concentration and nature of subsurface fluids, rock type and thermal properties, rock fluid permeability, rock hardness and other mechanical properties, and local stress (e.g., evidence of seismic risk). These data let geologists and engineers build models of the subsurface rock and potential underground geothermal reservoir and allows the project team to assess the geothermal potential and estimate the cost of drilling wells.

Effective planning and exploration depend heavily on high-quality databases of geological survey data, ideally ones tuned to geothermal exploration: looking for hot deep rock or a hydrothermal reservoir is not the same as looking for nickel deposits or oil. Thus, there is an important government role supporting the early high-risk stages of the geothermal project lifecycle. For example, the US Department of Energy has partnered with the US Geological Survey to develop datasets and fund geothermal research projects.[4] Similarly, the United Nations in 2017 created a harmonized standard for reporting data relevant to geothermal resources.[5] Such standardized data can help investors and project developers identify a resource and assess its potential risk and value.

Similar data have been published for parts of western Canada in 2018[6] and parts of Quebec in 2021[7]—but a full country analysis has not been conducted since 2012.[8] Overall, Canadian geothermal developers lack high-quality and easily accessible geological data, especially in areas far from the regions routinely surveyed for oil and gas in western Canada. There are practically no data for many parts of central and eastern Canada, and the data that do exist rarely cover depths that are relevant to deep EGS (>5 km beneath the surface).

The US Department of Energy's 2019 *GeoVision* report[9] emphasizes poor exploration success rate as a critical business risk barrier for geothermal. It attributes the poor success rate largely to limitations in subsurface exploration and resource confirmation capabilities. The report recommends a significant expansion of R&D over a broad range of capabilities and technologies to reduce exploration costs and improve early-stage success rates, including remote sensing technology, surface geochemistry, and field geophysics—as well as establishing a national agency to facilitate data aggregation and knowledge exchange. With fewer and lower quality geological data, Canadian developers face even greater planning and exploration challenges.

Test drilling and feasibility assessment

The purpose of test drilling is to assess the local geology and geothermal potential. This phase involves drilling one or more "production quality" wells into the proposed reservoir and using those wells to validate reservoir potential and modeling assumptions. Test drilling is more extensive (and expensive) than exploratory drilling and typically requires special approvals and permits. If the site is economically viable, the developer then uses data from the exploration and test drilling to estimate the build-out cost for the plant and potential product value from the sale of electricity and/or commercial heat. This process involves negotiating and signing contracts to sell the produced power at an acceptable price and, most importantly, obtaining the permits and regulatory approvals needed to proceed.

As shown in Figure 4, risk remains high through these first few stages, reflecting the fact that it is hard to identify and validate good geothermal sites. Indeed, only 18 to 25 percent of initiated geothermal projects (primarily hydrothermal, including a small number of shallow EGS projects) proceed as far as well field development.[8]

The planning, exploration, and test drilling stages of the geothermal project lifecycle represent a small portion of the overall cost but can take a long time to complete, because in most countries (including Canada) approval processes (for permits, regulatory certification, power grid integration, and financing) are not streamlined or designed to support geothermal projects. Of course, consultation and engagement with key local stakeholders becomes even more important as the project transitions from test drilling and feasibility assessment to well-field development.

Note that well-field development requires testing the field to make sure the reservoir can deliver sufficient heat (at sufficiently high temperature and flow rate) to generate electricity without the reservoir cooling down. As a result, *some* facilities construction may be needed alongside test drilling, since engineers need infrastructure to test the geothermal extraction and injection cycle.

Project risk is continually reduced as new wells add to knowledge about reservoir capabilities. Thus, it makes sense to build test wells (and testing infrastructure) early, delaying heavy investment in other infrastructure until the site is proven. Moreover, with this added knowledge, project developers can revise financial forecasts and construction plans to align better with the available resources.

3.3 Production well drilling and well completion

Production well drilling

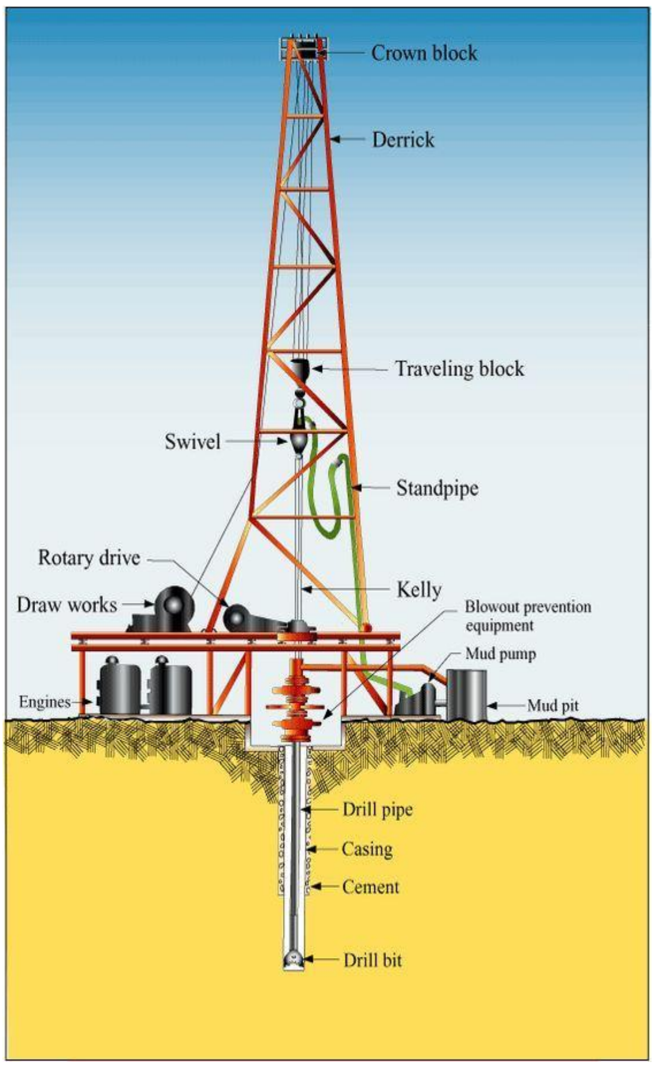
The business and technology of geothermal drilling have been substantially inherited from the oil and gas sector, which has benefited from more than a century of intense R&D. In what follows, we adopt the standard oil and gas terminology, while emphasizing aspects of drilling that are uniquely relevant to geothermal.

Despite careful planning, a substantial fraction of drilled oil and gas wells (perhaps on the order of 50 percent) are not economically successful.[10] The success rate is even lower for “wildcat” drilling (in new, unexplored regions) where the success rate can be below 20 percent.[11] However, in an identified oil, gas, or geothermal field, success rates substantially increase as more wells are drilled and the field becomes better understood.

For most oil and gas exploration companies, economic success is averaged over many wells; they are generally little concerned about a few “dry” wells. A 50 percent success rate can be economically sustained, if the return on successful wells exceeds the cost of the full portfolio of drilled wells. Indeed, a 20 percent success rate can be sufficient, if successful wells are highly productive. And when drilling into a new field, the success rate often increases for subsequent wells as the field is better mapped.

This situation is similar for geothermal drilling. Quoted well success rates start at around 50 percent in the exploration and test drilling phase, with higher success rates as a project moves to operational mode, reflecting improved knowledge of the underground geothermal production zone.[12] Of course, oil and gas exploration has the advantage of a much higher rate of drilling per year (see Section 4.2).

Figure 5. Simple schematic of a drilling rig and well
(Source: Wikimedia Commons)



Using data generated in the exploration and test drilling phases, the developer begins production drilling by planning various aspects of the operation, including: the initial size of the drill hole (so the bottom of the hole will be sufficiently large for the desired flow volume), the drilling target depth, location and drilling path to that location (if not straight down), the likely casing program (how many casings strings needed and at what depths), the types of drill bits best matched to the rock at different depths, and the types of mud (weight, chemical composition) needed for different zones.

Figure 5 is a simple schematic of a drilling rig and well.[13] The rig at the top holds and powers the drill. A shaft (constructed from sections of drill pipe sections) called the *drill string* connects the rig to the drill bit, which grinds against the rock at the bottom of the hole, breaking it up into small fragments. The grinding arises from a combination of the physical rotation of the drill bit and the downward pressure on the drill string.

While drilling is underway, the hole is filled with *drilling mud*: a heavy, viscous liquid that is pumped down the interior of the hollow drill string and then flows upwards via the borehole back to the surface, carrying with it the rock cuttings produced by the drill bit. At the top of the well, the mud is filtered to remove the rock debris and is then reinjected into the well.

With some types of drill bits, the mud flow actually drives a low-velocity motor at the bottom of the drill string to power certain types of drill heads or other so-called *down well* equipment, such as motors that steer the drill. The mud serves several other purposes, such as pressurizing the hole so that, when drilling through regions saturated with high-pressure gas or liquids, the “back pressure” of the mud keeps the wall of the well from collapsing and/or stops liquids or gases from leaking into and contaminating the mud. During drilling, the rock debris coming out of the well is examined to assess the nature of the rock at the drill face, creating a map of the geology the drill is passing through.

In some cases sensors are also placed on the *bottom hole assembly* (the section of tubing at the bottom of the drill string, to which the drill head is attached) to measure local properties such as the magnetic field, radiation levels, drill vibration, and the angle of the drill head to give the well operator information about what is happening at the bottom of the hole, or the ability to better control and steer the drill.

Mud pressure is continuously monitored to make sure the borehole is stable: a sudden pressure change can mean the drill has encountered a potentially risky underground formation. Sometimes drilling hits regions (of oil, water, gas) that produce sufficient backpressure to force the mud, drill string, and other equipment out the top of the well. To prevent such “blow outs” wells are topped with a *blowout preventer*, which triggers automatically if the pressure becomes too high.

If the blowout preventer is triggered, or if the well pressure simply rises too much, the drill operator can raise the mud pressure (in some cases by replacing the existing mud with mud that is denser and heavier) until the added weight counteracts the pressure increase.

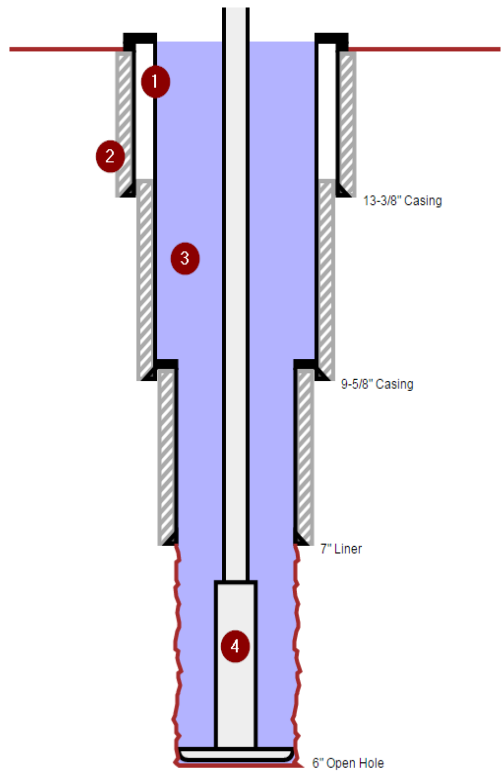
Eventually the weight/pressure of the mud can start to damage the rock wall along portions of the well. For example, the pressure needed to stabilize the well 1,000 meters down may be damaging to the well at only 400 meters’ depth. At this point drilling needs to stop and the drill operator needs to line the well with a *casing string*—a string of joined sections of pipe that fits inside and lines the drilled hole from the top down to a chosen depth, covering the vulnerable section of the well. Once lowered into the well, casings are cemented into place by forcing cement down into the space between the casing string and the surrounding rock. Once this cement has hardened, drilling restarts below the installed casing.

Conversely, drilling can encounter a *loss circulation zone* where some or all of the mud does not return up the well but is instead lost into the fractured or otherwise permeable rock surrounding the hole. In some cases, drilling can continue through such zones by adding materials to the mud to slow or stop the loss. But in many cases, a casing string must be inserted to seal off the well and keep it from leaking.

Figure 6 illustrates a well with three casing strings.[14] The actual geology determines how many casing strings are needed, but in general deeper wells require more strings than shallow ones—as many as five or six. Since each string must be lowered down inside the preceding one, this means the “effective” diameter of the hole shrinks with each added string. It also means, when installing a casing string, that the drill team needs to: stop drilling, pull up the drill string, assemble and lower the casing string, cement it into place, and then re-lower the drill. This process is time-consuming and expensive—and gets even more so as the well depth increases. *The net result is that drilling cost has a nonlinear relationship with well depth.* For example, a well that is 3 km deep is likely many times more expensive than one that is 1.5 km deep.

Figure 6. Casing strings

(Source: Wikipedia) The black vertical lines with a triangle at the bottom represent a steel casing or section of liner, while the grey hatched boxes represent the cement used to fix the casings in place. Blue represents the drilling fluid/mud and the white pipe in the middle is the drill string.



Wells and well fields are often more complex than the simplified model described above. Some well boreholes fork into multiple holes to gain access to different zones. Similarly, a single drilled well may, along its length, pass through and provide access to multiple production zones at different locations along the well. In addition, directional drilling (with motors that can steer the drill head) allows drill bits to be steered horizontally or vertically so they can reach a target zone.

Well completion

Drilling is finished and a well is ready to be *completed* when the well is drilled to the desired depth and has been tested to confirm it can perform the desired task. For a traditional oil or gas well, this typically means testing that the well produces sufficient oil or gas to make the well economical to operate. For a geothermal well, "ready to be completed" means ensuring the extraction flow rates and fluid temperature are high enough that the well can deliver economically sufficient thermal energy. However, most geothermal wells are drilled in pairs (or groups of pairs) with one well extracting hot fluid and the other returning cooled fluid to be re-heated by the rock. Thus, additional testing must be conducted to confirm that the entire flow cycle works. For EGS, such testing may only be possible after a reservoir is artificially constructed.

If the well passes muster, it is completed and put into production mode. This stage typically involves casing the entire length of the well (so the well cannot collapse in on itself), running *production tubing* (pipe that will carry out the extracted resource) down to the *producing zones* (the regions where the product will be extracted or injected), and installing equipment at the top of the well to extract the product (or pump it down the well) and in other parts of the well to help the product move between various zones. When this work is completed, the rig is removed and replaced by a production wellhead, also called the *production tree* or *Christmas tree.*

3.4 Reservoir construction

For conventional hydrothermal resources, hot water or steam is extracted from naturally occurring reservoirs. However, for EGS, a reservoir must be constructed or *stimulated* to hold fluid injected into the well that is heated by the rock and eventually extracted.

The basic requirements for such a reservoir are simple. First, fluid must flow from the injection to the withdrawal wells with little to no loss. Second, the fluid flowing from the injection to the withdrawal wells must be sufficiently heated by the hot reservoir rock it passes through. And third, there must be a sufficient transfer of heat from the surrounding rock to the reservoir rock (via direct heat conduction or the flow of hot convective fluid) that fluid extraction does not deplete the reservoir heat source. If the reservoir heat source starts to cool, fluid extraction flow rates must be lowered to maintain the temperature of the fluid being extracted.

Technically, there are two things that can be controlled to engineer this environment: the manner in which the hot rock is "enhanced" or "stimulated" and the depth and placement of the injection and withdrawal wells.

A number of techniques (many borrowed from oil and gas drilling) can be used to enhance or stimulate the rock formation to create a reservoir.[15] The most common technique is hydraulic fracturing (i.e., fracking), in which high-pressure fluid is injected into the reservoir region to fracture the rock (creating pathways for water to flow) and to fill the otherwise dry reservoir. To this fluid one can add "proppants" (i.e., sand) that prop open the cracks so fluid can continue to flow. In some cases, chemicals can also be used to open gaps by dissolving mineral deposits in the rock.

Geothermal extraction can often benefit from fracking that enhances the flow of water between injection and extraction wells in deep hot rock that is dry and impervious to water flow. Hydraulic fracturing can expand and create gaps in the rock to allow the flow of water, and then be used to fill this newly created space with pressurized water to create a usable and localized geothermal reservoir.[16]

To ensure efficient and sustainable fluid heating and flow, decisions around well placement and stimulation must be tailored to the nature of the rock of a given reservoir. But there is often significant uncertainty about rock formations until one or more production well have been drilled. If the placement of the wells is not ideal, stimulation techniques may not be enough to effectively link extraction and (re)injection wells. Leaks also pose a risk to the reservoir construction process, with fluid flowing out of the reservoir and never returning to the extraction wells. Some leakage may be acceptable if the rate is low. But such a system will require the continuous addition of new fluid, which may not always be feasible. Lastly, the reservoir may ineffectively heat the fluid. This risk can emerge if the fluid does not pass through enough hot rock, if the natural reheating process is too slow to keep the rock hot, or if the fluid flow is *short-circuited*—that is, it is concentrated in a small number of rock channels that cool quickly, rather than being heated through many small pathways in the rock.

Several new techniques and technologies are in development to improve reservoir construction, including the "hydroshearing" approach developed by AltaRock energy.[17] An even more radical method is being developed by Calgary-based Eavor that uses closed loops of piping installed through hot rock. Fluid is pumped into the loops, which is then heated as it passes through hot rock zones (much as happens in a water boiler), driving a turbine at the surface.[18] Eavor recently received a 40 million USD investment from BP and Chevron to build a geothermal station using this technology.[19] The method could be particularly valuable for deep EGS in regions of extremely hot rock.

3.5 Power plant construction and power generation

Power plant construction

Power plant construction may overlap with well-field development, as some power plant infrastructure may be needed to test the well and reservoir. This construction phase includes building the facilities and power system components responsible for turning heat energy into electricity, such as turbines, electrical generators, and control systems. It also involves constructing power lines connecting the station to the power grid, installing power transformers and supporting electrical systems, and building access roads. In power engineering parlance, many of these tasks are often referred to as *Balance of Plant* (BOP)—the supporting and auxiliary components that keep the plant running and delivering power to the consumer but that are secondary to the components responsible for the actual production of electricity (turbines and generators).

The physical plant is the most straightforward component of the power station. The main difference between geothermal and other electricity generation, as noted at the end of the previous section, is that geothermal offers the option for incremental build-out of both the reservoir and the power conversion infrastructure, which can help to minimize early capital expenditure.

Power generation

Geothermal mainly uses conventional heat-engine and electrical-generation technology. Converting heat into electricity is straightforward: first, a heat engine (typically a turbine) is used to convert heat to mechanical energy and, second, the mechanical energy is used to turn an electrical generator. The basic technology has existed since the mid-1800s, when early reciprocating steam engines powered the first electric dynamos to deliver continuous electric power.[20] All modern thermal power plants (including nuclear plants) work this way, albeit with the benefit of over 100 years of steadily improved technology.

Geothermal stations can exploit fluid temperatures ranging from 80-380°C at a wide range of pressures and fluid flow rates. The appropriate heat engine design depends on all these parameters. The design must also account for a hot "working fluid" that is not pure water (as in a traditional thermal power station) but is rather full of dissolved minerals, salts, and gases, which may call for special materials or maintenance processes to minimize corrosion.

Power conversion efficiency decreases as the fluid temperature decreases, but it also depends on factors such as fluid pressure, flow rate, and the nature of the reservoir fluid. Conversion efficiency for current geothermal plants can range from a few percent up to 15 percent.[21] However, power conversion technology is rarely a “make-or-break” factor for the feasibility and profitability of a geothermal system. Access to a low-cost, high flow rate heat source is by far the most important determinant of success.

There are three main heat engine types relevant to geothermal electricity generation, each covering different ranges of fluid temperatures: dry steam, flash steam, and binary cycle. Some companies have also developed modular power conversion units designed to support geothermal systems that scale up over time.

Dry steam (>380°C). A small number of existing geothermal systems produce hot fluid in the form of dry steam—that is, steam so hot it contains no suspended water particles. Dry or superheated steam is ideal for power generation as it can directly drive a steam turbine. The steam expands through the length of the turbine, driving turbine rotation (pushing on the turbine blades), cooling and reducing pressure as it passes through the turbine, and thereby converting thermal energy to mechanical energy. The lack of suspended water droplets minimizes damage to the turbine blades.

If the steam source is hot enough and of sufficiently high pressure, there may be a second turbine stage optimized for a lower range of temperature and pressure. After leaving the final turbine, the cooled, low-pressure steam passes through a heat exchanging condenser to convert it back to fluid. This process improves the efficiency of the last turbine stage (by reducing the outflow temperature). The cooled fluid can then be reinjected into the geothermal reservoir for reheating. If the steam is corrosive or contaminated by particulate matter that will damage the equipment, the plant can use heat exchangers to heat clean water that is then used as dry steam in the turbine. Although this stage reduces efficiency, it may be worth the loss if it also reduces ongoing maintenance costs.

Flash steam (180-380°C). Flash steam plants require a hot reservoir (but not as hot as required for *dry steam*) producing fluid under high pressure. The hot pressurized fluid is fed into a tank held at a much lower pressure (called a flash tank). Some of the fluid will then *flash* (rapidly vaporize) into dry steam, which then drives a steam turbine. Not all the fluid will flash—some remains a liquid. If the temperature and pressure of the remaining fluid is high enough, it can be fed into a second, lower-pressure flash tank, flashed again, and then used to power a lower-pressure turbine. In some cases, a third such stage may be possible. A few hydrothermal power stations that produce sufficiently hot, high-pressure fluid currently use flash steam technology.

Binary cycle (80-180°C). Since 2000, roughly 90 percent of the geothermal capacity built in the world has used binary cycle technology.[22] At temperatures less than 180°C, water-based geothermal fluids cannot efficiently flash due to the physical properties of water. The solution is to move the thermal energy from the geothermal fluid to a second fluid with a much lower boiling point, and flash that second fluid to drive one or more turbines. This two-step process is called a “binary cycle”: two fluids and two independent closed loops.

In this kind of plant, a heat exchanger transfers heat from the geothermal fluid to a low-boiling point working fluid, such as a butane, isobutane or even ammonia, that is kept under high pressure. The cooled geothermal fluid is then reinjected back into the geothermal reservoir. The heated working fluid is converted to high-pressure vapor that drives a high-pressure turbine. Like flash steam plants, there may also be a second, lower-pressure turbine stage if there is sufficient heat in the working fluid to “reflash” it at a lower pressure.

Modular power conversion. Most large power engineering firms can custom-build large-scale power stations to convert heat into electrical power. But a few companies also sell modular power conversion units (integrating a heat engine with electricity generation) suitable for geothermal and tailored for different ranges of fluid flow rates and temperature. Such modular units support *scalable* geothermal power station construction: plant owners can drill a small number of successful wells, install modules, start generating power and cash flow, and then repeat, which minimizes up-front capital investment. Most of the modular power unit companies operating in this space focus on lower-to-mid-range temperature resources (80°C to 150°C).[23,24,25]

Lastly, it is worth recalling that a geothermal power plant can only be successful if it has negotiated long-term contracts with a grid to which it can deliver the produced power. Other green energy alternatives (such as solar PV, wind, or pumped hydro) often enjoy financial incentives, such as preferential connection to local grids, or feed-in tariffs to subsidize early plants. Such incentives are typically not available to geothermal operators, and indeed in some cases, geothermal projects have been unable to find, often due to lack of Government support, grid partners willing to buy the electricity they could produce.[26]

Lifespan of a geothermal power plant

Wells operate as long as they are profitable. Oil and gas well lifetimes range from a few years to 20 years, depending on the flow rate and the market value of the product. Note that, in general, wells cannot easily be turned off or *shut in* and restarted later: the geology of underground reservoirs is complex and dynamic, so in most cases shut-in wells do not return to their initial flow rate. Moreover, stopping flow can lead to corrosion or other problems with tubing or other equipment, making it expensive (and often uneconomical) to service and return a shut-in well to production.

Geothermal wells typically operate continuously for as long as possible, with lifetimes of 30 years or more. This means it is important to invest appropriately in construction and completion work to make sure the well has a long operational lifetime and low long-term maintenance cost. Thus, all other things (such as size, depth, complexity) being equal, a geothermal well to a given depth will be more expensive than an oil or gas well, as the geothermal operating model warrants investing more money in longer-lived well components such as valves, casing, and tubing.

Notes

[1] Current experience is based primarily on power stations leveraging hydrothermal reservoirs. EGS-based plants will have a similar lifecycle but with a greater percentage of cost associated with drilling and well-field development.

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[10] Although the term “success rate” (or “success ratio”) is often used to characterize oil and gas drilling performance, there is much wiggle room in defining the status of completed wells, and most companies are strongly motivated to label wells successful. Thus stated success rates or ratios are undoubtedly biased upwards. Kunjan, B. (2016). “Exploration chance of success predictions: Statistical concepts and realities.” *ASEG Extended Abstracts* 2016(1): 1-8. https://doi.org/10.1071/ASEG2016ab150.

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[21] A heat engine's "thermodynamically ideal" efficiency is given by the formula 1 – Tc/Th, where Tc is the temperature of the cooled fluid leaving the engine and Th is the temperature of the hot geothermal fluid entering it (both in degrees Kelvin: °C + 273.15). For a geothermal fluid at 150°C (423.15°K) and exiting at 50°C (323.15°K), the maximum efficiency is then only ~24 percent. Importantly, real-world efficiency is always lower than thermodynamically ideal efficiency, due to engineering and cost constraints.

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4. The deep EGS drilling challenge

Key messages:

- Deep EGS requires transformational improvements in drilling technologies to make deep drilling technically and financially feasible.
- With existing drilling technologies and techniques, it is feasible to drill through hard rock to depths around 10 km at a cost between 50 and 100 million USD per well. These costs need to be reduced by an order of magnitude (to 5 to 10 million USD) to make deep EGS economically viable in the current energy market.
- Emerging technologies, such as percussive, water-jet, and plasma drilling, offer pathways towards cost-competitive drilling through hard rock.
- Investment in R&D for deep, hard rock drilling is approximately 20 million USD per year worldwide. To achieve economic viability within a reasonable timeframe, investment must grow by more than an order of magnitude—to approximately 500 million to 1 billion USD per year.
- Canada provides small amounts of funding to deep, hard rock drilling R&D, but these investments lack sufficient scale and an overarching strategy.

4.1 Introduction

Research, development, and demonstration (R&D) gaps exist across the geothermal project lifecycle, but the technical challenges associated with exploration, reservoir construction, and power generation are generally straightforward. By comparison, the gap between current drilling capabilities and what is required for economically viable deep EGS is significant—and the actions necessary to close that gap are unclear. This section attempts to clarify the drilling R&D challenge and sketch out the most promising technological pathways for overcoming it.

The prospect of a Canadian deep EGS breakthrough hinges on drilling: if drillers cannot reach deep hot rock economically, they cannot build deep EGS plants. Drilling and reservoir construction (the latter essentially an offshoot of drilling) are responsible for 50 percent or more of the overall costs of existing geothermal systems. The deeper the well, the higher the cost and risk. Unlocking the tremendous potential of geothermal resources in Canada and around the world depends on a massive leap in drilling capabilities alongside dramatic improvements in reliability and reductions in cost.

We need to be able to drill 10 or more kilometers through very hard igneous and metamorphic rock. Today's drilling technologies are not up to the task: existing techniques are too slow, too expensive, and too energy intensive. However, emerging drill bit technologies are already demonstrating ways these challenges might be overcome. These R&D advances are happening despite a chronic lack of investment in one of the few promising solutions to the world's baseload net-zero electricity deficit.

This section focuses on the core R&D challenge: *cost-effective, low-carbon deep drilling through hard rock*. It also examines the relationship between geothermal and the oil and gas sector—and specifically how fossil fuel companies can spur innovation around deep drilling. Lastly, it examines emerging drilling technologies and other innovations relevant to geothermal systems, including geothermal "battery" storage and the use of sequestered CO_2 (rather than water) as a working fluid.

4.2 Defining the drilling challenge

Transformative improvements in deep hard rock drilling are key to enabling deep EGS. To get to the heart of what this means, we need to answer three questions:

1. How deep can we currently drill through "hard" rock (and at what cost)?
2. What is the cost-per-well target for deep EGS (and what is the gap between current drilling costs and that target)?
3. How much is being invested today in deep, hard rock drilling R&D (and how much is needed to overcome the drilling challenge)?

How deep can we currently drill through "hard" rock (and at what cost)?

*With existing drilling technologies and techniques, it is feasible to drill through hard rock to depths around **10 km**. Such a well would likely cost between **50 and 100 million USD**.*

For soft sedimentary rock, oil and gas drillers can already drill up to 15 km if there is economic value in doing so. Such wells are not drilled straight down but are instead drilled down and then horizontally for many kilometers into oil- and gas-producing regions. There exist significant data about the well-completion costs associated with drilling wells of different lengths through soft rock.

However, few data are available on the cost of deep drilling through hard metamorphic or igneous rock. Such drilling has been largely conducted by geological research projects that were neither drilling for speed and cost-efficiency nor aiming to assess the economics of deep drilling. Usually, it is even difficult to determine the total funds spent on a given project. While official figures may state, for instance, that a given research agency spent a certain amount, those figures do not indicate what other resources were contributed by business-partner R&D investments, academic institutions that participated in the project, and the like.

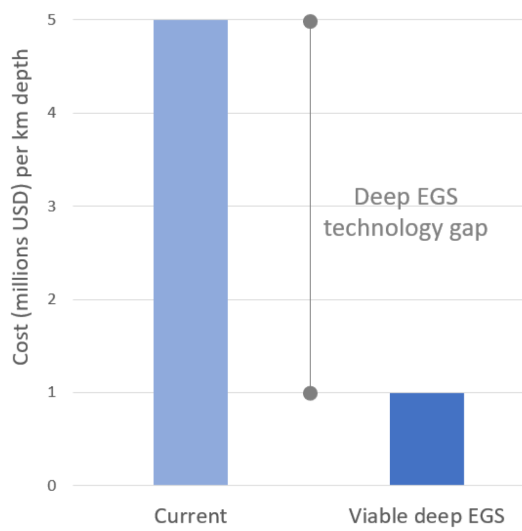
One active research project is Iceland's Deep Vision project,[1] which has produced test wells at depths of 4 to 5 km through hard basalt. Previous projects like the Soviet Union's Kola well (1970-1989) and the German Continental Drilling Programme (1987-1995) produced holes with depths of 12 and 9 km respectively.[2] The Continental well encountered significant metamorphic rock. In the case of the Kola well, the near 20-year project drilled a borehole pushed through layers of granite and basalt, and at its deepest extent, the plasticity of the rock under heat halted the drilling.[3] The hole had a diameter of only 9 inches and cost about 100 million USD.[4] It is impossible to determine precisely what portion of this total was drilling cost, but it seems reasonable to assume at least half went to drilling, or between $50 and $100 million USD.

What is the cost-per-well target for deep EGS (and what is the gap between current drilling costs and that target)?

Financially viable geothermal power stations currently require well costs to be in the range of ***5 to 10 million USD****. Thus costs need to be reduced by* ***an order of magnitude*** *to make deep geothermal economically viable in the current energy market.*

Using aggregated geothermal well-cost data from Rystad Energy,[5] we estimate that the average cost-per-well for an economically viable geothermal power station is approximately 5.3 million USD.[6] However, the acceptable cost-per-well may be slightly higher with potential subsidies like feed-in tariffs, depreciation incentives for zero-carbon projects, and/or long-term financing mechanisms discussed in Section 6. Therefore, we estimate a conservative cost-per-well target at 5 to 10 million USD, not including adjustments for long-term financing mechanisms. Note also that removing incentives and subsidies for carbon-intensive electricity sources could also raise the overall price of electricity and make higher-priced geothermal projects more cost-competitive.

Figure 7. Deep EGS technology gap

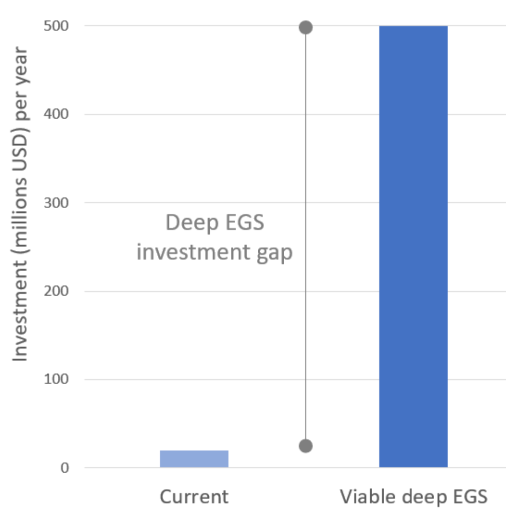


How much is being invested today in deep, hard rock drilling R&D (and how much is needed to overcome the drilling challenge)?

Investment in R&D for deep, hard rock drilling is approximately ***20 million USD per year*** *worldwide. In order to achieve economic viability within a reasonable timeframe, investment must grow by more than an order of magnitude—to approximately* ***500 million to 1 billion USD per year****.*

Data on industry and government investment in deep, hard rock drilling R&D are scarce, but the technology does not seem to be a significant government or industrial R&D priority anywhere in the world.[7] Based on our analysis of Statistics Canada data (see Appendix 5), annual Canadian investment in deep, hard rock drilling R&D is perhaps around 1 million USD.[5] European and US data are even harder to come by, but based on the limited data available, and by extrapolating from Canada's R&D spending (adjusting for the relative sizes of the economies of the US, EU, and Canada), we estimate European investment to be in the range of 5 to 7 million USD per year and US investment to be approximately 10 million USD per year (see Appendix 5). We also conclude that deep drilling is not an R&D priority for large drilling equipment companies, as their priorities are driven by clients (oil and gas companies) who have little need for improved hard rock drilling.

Figure 8. Deep EGS investment gap



We believe that it will take several years to develop and prove the necessary hard-rock drilling technologies, with required investments in the low hundreds of millions per year. But this R&D needs to be part of a broader program focused on using this drilling technology to deliver economically viable deep EGS—a program that builds pilot deep EGS plants and integrates new technologies into the end-to-end project lifecycle. We estimate that the total cost of such a program, incorporating both elements, would be in the range of 300 to 500 million USD per year.[8] Ideally, some of the investment in drilling and testing would be recovered when test wells evolve into operational deep EGS power plants.

4.3 The relationship between geothermal drilling and oil & gas

The oil and gas sector is largely responsible for past and present innovations in drilling. In 2019, over 70,000 oil and gas wells were drilled around the world (5,400 in Canada),[9] compared with around 230 geothermal wells.[10] Therefore, oil and gas drilling needs tend to drive the development of new drilling technologies and techniques. Geothermal drilling heavily leverages the technology and terminology of oil and gas drilling, albeit with some unique needs and challenges. The sheer number of oil and gas wells drilled every year provides both ample opportunities to test and refine new ideas, as well as financial incentives for doing so.

In 2019, between 200 and 400 billion USD was spent on oil drilling alone.[11] The sheer size of this expenditure means that oilfield drilling and service companies (the latter being firms contracted to build the drilling and drilling-support equipment, conduct well testing, and provide post-drilling well-operation and maintenance services) have strong financial incentives and many opportunities to spend billions each year on R&D to decrease costs associated with drilling and extraction.[12] In contrast, the incentives and opportunities for geothermal companies are extremely low.

Table 2 summarizes key differences between petroleum and geothermal drilling. The main takeaway messages are:

- geothermal wells are mostly drilled in geological regions different from and less well-understood than those supporting oil and gas (for deep EGS, drilling is deeper and through much harder rock);
- geothermal wells are generally wider in diameter to support higher fluid flow rates;
- geothermal wells are often drilled through, and operate, in much hotter environments; and
- geothermal wells require longer (30+ year) lifespans, which means they must be designed to minimize corrosion and other forms of damage.

Table 2. Geothermal vs. Petroleum
(Adapted from *Augustine 2016*[13])

Attribute	Geothermal	Petroleum
Temperature	150-350°C is "normal"	150-175°C is "hot"
Flow rates	~5,500 US liter/min is "average"	~550 US liter/min is "high flow"
Drilling	Vertical + directional drilling; deeper average boreholes; 20–30 cm diameter production	Vertical and extended reach horizontal ("fracking runs"); 13-18 cm diameter production
Flow rate and well lifespan	Constant flow for 20-30+ years	High initial flow (months) Declining over time (3+ years) Maximum lifetime (~20 years)
Lithology (type of rock)	Volcanic (soft)/intrusive igneous (hard)/metamorphic (hard)	Sedimentary (soft to hard)
Facies (character of rock formations)	Complex, often fault-dominated	Stratigraphy of sedimentary structures
Recovered product and value	Heat (hot water): ~0.25 cents/barrel[14] → $12,860 USD/day (average)	Petroleum: ~$40/barrel → $206,000 USD/day (high flow)

4.4 Emerging drilling technologies

Oil and gas drill bits vary in their design according to the type of (primarily sedimentary) rock formations they are expected to encounter. The goal is to achieve efficient drilling, where "efficient" essentially involves a trade-off between the drill string's rate of penetration through the rock ("ROP," in meters per hour) and the bit's lifespan. (Changing the bit is a time-consuming operation requiring complete removal of the string from the drill hole.) In ideal rock conditions, some drill bits can achieve rates of penetration of 20 or more meters per hour.[15]

Most drill bits are designed for sedimentary rock, because soft rock drilling is the focus of almost all commercial oil and gas clients. Unfortunately, such bits fare poorly against hard igneous or metamorphic rock, such as granite, where ROP may drop to 1 meter per hour or less, with bits wearing out quickly and needing frequent replacement.[10] Traditional drill bits are thus unsuited for deep EGS, which invariably involves substantial drilling through extremely hard rock.

Several new technologies could greatly reduce drilling costs, particularly for deep drilling into hard rock.

Improved hard rock drill bits

Transformational improvements in drill bit technology are needed to unlock deep EGS. The US *GeoVision Analysis Supporting Task Force Report*[16] (published by Lawrence Berkeley Laboratory) provides an overview of several options, the most promising of which include:

- *Percussive drilling*. As opposed to conventional rotary grinding, the drill bit percussively hammers vertically against the rock face, fracturing the rock. Drill bits under development have achieved an impressive ROP of 23 metres per hour through hard granite.[5] One of the main players in this area is Strada Global, which is developing percussive drilling technology with a focus on geothermal projects.[17]
- *Water-jet drilling*. Conventional and percussive drill heads may be augmented with high-pressure water jets (similar to water jets used to cut steel) to fracture the rock surface. Canadian researchers have recently proposed augmenting Strada's percussive drill bits with water jet technology.[18]
- *Plasma drilling*. Rapid pulses of high temperature (>2000°C) plasma can vaporize and fracture the rock face without the drill ever touching the rock. Plasma drilling could be very effective for hard rock and, since it is contactless, the bit never needs to be replaced.[19] The Slovakia-based company GA Drilling is one of the main players developing plasma drilling technology.[20]
- *Millimeter microwave drilling*. This emerging technology uses gigahertz (GHz) frequency microwave radiation to weaken the surface of hard rock, making it easier for drill bits to cut and fracture the rock.[21,22] This technology is apparently being pursued by US-based AltaRock Energy, a small EGS-focused geothermal development company based in Seattle, WA , and also by Quaise energy, a well- funded startup founded out of MIT.[23,24]

It is not clear that any one drilling technology will solve the deep EGS drilling challenge. Different types of hard rock may require different technologies or combinations of technologies. Therefore, investments should be made in all these potential solutions (and likely others as well).

Expandable tubular technology

Expandable tubing systems are used to increase the well casing's diameter. A new string of casing is dropped into the hole through the last-installed casing string and then, once in place below that string, expanded to the same diameter. This technology allows drillers to maintain nearly the same hole diameter for the full length of the well. It reduces the cost of drilling the upper portions of the well, because they do not have to be so large in diameter, and it also reduces the risk of discovering, at depth, that additional casing must be installed but the borehole diameter is insufficient to accommodate it.[25] Indeed, there is evidence that using expandable tubing can greatly reduce drilling time (by a factor of three or more) and therefore cost when drilling deep.[26]

High-temperature muds and cements

Traditional muds and cements used in oil and gas drilling are mostly designed for temperatures below 150°C and can fail at the higher temperatures encountered in hot geothermal wells. New muds and cements are being developed for hotter environments,[27] but additional R&D will be needed to produce materials for even higher temperatures and pressures.

Corrosion- and deposit-resistant tubing

When a well is in production, chemical reactions between the product and tubing can corrode or otherwised9 damage the tubing or cause buildup of deposits inside the tubing. The tubing can then leak, or the flow inside the tubing can be restricted. These problems are well understood in oil and gas production, and various approaches have been developed to mitigate them, such as choosing appropriate tubing alloys or coating the inside with protective polymers.

Geothermal wells present similar problems, particularly given their long lifespans. Work on hydrothermal and shallow EGS wells to date has provided abundant data and practical lessons that can help a ramped-up EGS program develop best practices for building long-lived geothermal wells.

4.5 Other emerging geothermal technologies

Geothermal batteries: Alternative energy storage

A shallow geothermal reservoir could be used to store high temperature fluid that is later withdrawn for heating and/or to generate electricity.[28,29] Conceptually, the technology would be similar to that of a battery: the fluid is charged (heated), and the stored (thermal) power is used subsequently when needed.

This technique has potential benefits over traditional batteries or pumped hydro storage, both of which can generally provide electricity for only a few hours or days before they are exhausted. A heated geothermal "battery," however, could provide output for several months. This greater capacity would make them useful in the far north or south, for example, to store heat produced from solar or wind during the summer, which could then be withdrawn in winter for district heating or electricity generation.

Supercritical carbon dioxide: Working fluid plus carbon sequestration

Several scholars have proposed using supercritical CO_2 (instead of water) as the reservoir fluid.[30] Massive quantities of CO_2 would be injected into a hot rock formation to create a reservoir. The reservoir's high pressure and temperature would keep the CO_2 in a supercritical state, with the gas stimulating rock porosity in the same manner as water. Compared to water, however, CO_2 flows more easily through tubing and rock (improving flow rates), reacts less with piping (potentially reducing maintenance costs), and has a lower critical point temperature (providing more efficient electrical power generation in turbines). As a bonus, this approach could permanently sequester large amounts of CO_2 when the reservoir is decommissioned. In 2020, GreenFire Energy presented results of a pilot trial of the supercritical CO_2 approach for heat mining, but not for conversion of that heat into electricity.[31] Although the results of this trial were promising, substantial additional development work is needed to advance this method from an intriguing idea to an economically viable option.

4.6 Canadian context: Technology and research players

A small number of geothermal-focused Canadian academic institutes and scholars are focused on technological, legal, regulatory, and other obstacles facing the geothermal energy industry in Canada. There are also two industry-academic associations that facilitate networking and collaboration: the Canadian Geothermal Energy Association (CanGEA) and Geothermal Canada. Various Canadian national and provincial research agencies (e.g., NSERC, Alberta Innovates, Natural Resources Canada) also fund a variety of geothermal-related projects, ranging from basic R&D to actual pilot plants.

There is a lack of coordination and focus between and among the nodes of this network, however. For example, no national or provincial funding agency has made geothermal an area of strategic focus. As a result, the small amount of funding available is distributed without an overarching strategy that covers the broad portfolio of geothermal's uncertainties and R&D gaps.

Appendix 4 lists associations, projects, companies, government agencies, and research institutions that make up the Canadian geothermal community.

Notes

[1] Elders, W. A. and G. O. Fridleifsson. (2005). "The Iceland Deep Drilling Project: Scientific Opportunities." *Proceedings of the World Geothermal Congress 2005,* Antalya, Turkey. https://www.geothermal-energy.org/pdf/IGAstandard/WGC/2005/0626.pdf.

[2] Ault, A. (2015). "Ask Smithsonian: What's the Deepest Hole Ever Dug? *Smithsonian Magazine.* 19 February 2015. https://www.smithsonianmag.com/smithsonian-institution/ask-smithsonian-whats-deepest-hole-ever-dug-180954349/.

[3] Wikipedia. (2022). Kola Superdeep Borehole. *Wikipedia.* Accessed 2 January 2022. https://en.wikipedia.org/wiki/Kola_Superdeep_Borehole.

[4] Hathcox, K., G. Marsch, and D. Ward. (2003). "What is the deepest hole ever dug into the Earth?" *Jackson Sun,* April 2003. https://www.uu.edu/dept/physics/scienceguys/2003Apr.cfm.

[5] Rystad Energy. (2021). "Geothermal power push points to record well count in 2021, growth set to bring billions to drillers." *Rystad Energy*. 16 September 2021. https://www.rystadenergy.com/newsevents/news/press-releases/geothermal-power-push-points-to-record-well-count-in-2021-growth-set-to-bring-billions-to-drillers/.

[6] According to Rystad Energy (*Ibid*), 182 geothermal wells were drilled in 2020 with a total CAPEX of 950 million USD. Assuming that the Rystad data are accurate and only include wells drilled for commercial power stations (as opposed to "experimental" wells), then we can simply divide the total CAPEX by the number of wells to get an average CAPEX per well. For 2020, the average CAPEX per well is approximately 5.3 million USD. We interpret this to mean that if one can drill an appropriately productive geothermal well (i.e., a well with sufficient temperature and flow rate) for ~5 million USD, then one can build an economically viable geothermal power station.

[7] Personal correspondence with Dr. Maurice Dusseault, Professor of Engineering Geology, University of Waterloo. https://uwaterloo.ca/earth-environmental-sciences/people-profiles/maurice-b-dusseault.

[8] This estimate is based on the following assumptions: (1) construction of 20 drilling test sites in Canada (and potentially around the world) spanning a variety of deep/hot/hard rock geologies; if each site costs about $10 million annually to operate, then the annual cost would be about $200 million; and (2) annual investment of $100 to $300 million in developing the larger suite of technologies (i.e., pilot plants, etc.) for deep, hard-rock drilling. Funding these two components would require a total annual budget of $300-500 million, and such a program would need to run for at least 5 years. Additional R&D investment would likely flow from drilling and/or geothermal companies interested in leveraging the opportunities provided by this program and infrastructure.

[9] Oil and Gas Journal. "2020 oil, gas drilling to hit at least 20-year low." *Oil and Gas Journal.* 14 July 2020. https://www.ogj.com/drilling-production/drilling-operations/article/14179504/2020-oil-gas-drilling-to-hit-at-least-20year-low.

[10] Between 2015 and 2020, roughly 1,160 geothermal wells were drilled worldwide, or an average 230 per year. Huttrer, G. W. (2020). "Geothermal Power Generation in the World 2015-2020 Update Report." Proceedings of the World Geothermal Congress 2020, Reykjavik Iceland. https://www.geothermal-energy.org/pdf/IGAstandard/WGC/2020/01017.pdf.

[11] If in 2019, 70,000 oil wells were drilled worldwide (Oil and Gas Journal. (2020). "2020 oil, gas drilling to hit at least 20-year low." *Oil and Gas Journal.* 14 July 2020. https://www.ogj.com/drilling-production/drilling-operations/article/14179504/2020-oil-gas-drilling-to-hit-at-least-20year-low.), and if the cost of drilling a well (on land – wells are more expensive when drilled underwater) ranged from 2.9 to 5.6 million USD (US Energy Information Administration. (2016). "Trends in U.S. Oil and Natural Gas Upstream Costs." *EIA.* https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf.), then between 200 and 400 billion USD was spent on such drilling world-wide that year.

[12] Kleinberg, R. and M. Fagan. (2019). "Business Cycles and Innovation Cycles in the US Upstream Oil and Gas Industry. *USAEE Working Paper No. 19-423.* https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3508466.

[13] Augustine, C. (2016). "The Differences between Geothermal and Petroleum: A Comparison." *SMU Geothermal Laboratory*. https://blog.smu.edu/geothermallab/2016/04/05/the-differences-between-geothermal-and-petroleum-a-comparison/.

[14] The "barrel" (abbreviated "bbl") is a unit of volume equal to 42 US gallons (almost exactly 159 litres) and is the oil standard unit of measurement.

[15] Real-world drilling ROP depends on a number of factors such as: size of the hole being drilled (smaller holes are faster); type of drill bit; type of rock being drilled through; and operational parameters such as drill rotation speed and the "weight on bit" (the downward pressure of the bit on the rock). Baujard, C., R. Hehn, A. Genter, D. Teza, J. Baumgärtner, F. Guinot, A. Martin, and S. Steinlechner. (2017). "Rate of penetration of geothermal wells: A key challenge in hard rocks." *Stanford Geothermal Workshop*, February 13-15, 2017. https://pangea.stanford.edu/ERE/db/IGAstandard/record_detail.php?id=27861.

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[18] Personal correspondence with Dr. Maurice Dusseault, Professor of Engineering Geology, University of Waterloo. https://uwaterloo.ca/earth-environmental-sciences/people-profiles/maurice-b-dusseault.

[19] Kocis, I., T. Kristofic, M. Gajdos, G. Horvath, S. Jankovic. (2015). "Utilization of Electrical Plasma for Hard Rock Drilling and Casing Milling." Paper presented at the SPE/IADC Drilling Conference and Exhibition, London, England, UK, March 2015. Paper Number: SPE-173016-MS. https://doi.org/10.2118/173016-MS.

[20] GA Drilling. (2021). "Plasmabit." *GA Drilling*. https://www.gadrilling.com/plasmabit/.

[21] Hassani, F., P. Radziszewski, and J. Ouellet. (2008). "Microwave assisted drilling and its influence on rock breakage: A review." *ISRM International Symposium 2008*, 5th Asian Rock Mechanics Symposium (ARMS5), Tehran, Iran. Paper Number: ISRM-ARMS5-2008-007. https://onepetro.org/ISRMARMS/proceedings-abstract/ARMS508/All-ARMS508/ISRM-ARMS5-2008-007/37957.

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[30] For example: Avanthi Isaka, B. L., P. G. Ranjith, and T. D. Rathnaweera. (2019). "The use of super-critical carbon dioxide as the working fluid in enhanced geothermal systems (EGSs): A review study." *Sustainable Energy Technologies and Assessments* 36: 100547. https://doi.org/10.1016/j.seta.2019.100547.

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5. Cost and environmental risk

Key Messages:

- Existing (hydrothermal) geothermal power stations can be very cost-competitive with other power-generating options. Shallow EGS stations are becoming cost-competitive.
- Deep EGS is not financially viable today due to the enormous up-front capital cost of drilling and reservoir creation.
- Financial risk can be mitigated by incrementally expanding plant capacity once a site is proven.
- In significant part because of its relatively high power density, geothermal has one of the lightest environmental footprints of all zero- or near-zero carbon power-generating technologies.
- Induced earthquakes are the biggest environmental concern, particularly with shallow EGS. Such risks are likely to be lower with deep EGS.
- Geothermal is less vulnerable to changes in temperature, wind, and precipitation caused by climate change than solar and wind power and hydroelectricity.

5.1 CAPEX, OPEX, and LCOE

This section reviews the cost breakdown of geothermal projects and the overall cost of geothermal power compared with other ways of generating electricity. Hydrothermal geothermal power plants are already often cost-competitive with other options. Shallow EGS is nominally cost-competitive, but high up-front capital costs present a challenge. These costs can be mitigated by financial and regulatory incentives. Deep EGS is currently not economically viable due to very high drilling and reservoir-completion costs. A technological leap in hard-rock drilling—and corresponding cost reductions—could make deep EGS cost-competitive and would substantially broaden the geographical range for EGS power plants (to most of Canada and the world).

Various measures allow comparison of costs between different types and sizes of power plants. Two are typically used: first, the capital cost/expenditure (CAPEX) to build a plant and, second, the ongoing operational cost/expenditure (OPEX) to keep it running. CAPEX is usually quoted as *cost per kW* (cost per unit of the station's maximum power output) and OPEX as *cost per kWh* (operational cost per unit of sold energy). The latter includes maintenance and support costs and, in the case of thermal or nuclear plants, the cost of purchased fuel.

A third measure, called levelized cost of energy (LCOE), assesses the economic viability of power stations. LCOE combines CAPEX, OPEX, the anticipated lifetime of the plant, and the plant's expected utilization rate to calculate the net present cost of electricity generation over the anticipated lifetime of the plant. Like OPEX, LCOE is quoted as a *cost* (per kWh) of a unit of sold electricity.

LCOE can also be understood as the *revenue* per unit of electricity sold that the plant must receive over its lifetime to pay off capital and operational costs and to deliver an acceptable profit to investors. It provides a litmus test for determining if building a plant makes sense—that is, how it stacks up against other plant types and whether customers are willing to pay more than the LCOE for its electricity.

Table 3 compares different power-station options based on their CAPEX and LCOE. CAPEX represents the up-front funds a developer must raise and spend before generating any revenue. LCOE allows comparison of the lifetime costs of different energy systems (in these estimates, using a 30-year payback period) and identifies which options have acceptable long-term economic value, even if they have an intimidating level of up-front CAPEX.

Table 3. Electricity source cost comparison (USD)[1]

	Electricity source	CAPEX ($/kW)	LCOE ($/kWh)	Cost Estimate Date, Notes, Source
1	Geothermal (hydrothermal)	2,400 – 6,200	0.07 – 0.12	(2019)[2]
2	Geothermal ('near hydrothermal' EGS)	9,000 – 10,000	0.1 – 0.3	(2019)[2]
3	Geothermal ('deep' [3-6km] EGS)	20,000 – 46,000	0.16 – 0.42	(2019) (low=flash, high=binary cycle)[3]
4	Hydroelectric	2,500 – 16,000	0.06 – 0.36	(2019)[4]
5	Solar (Utility PV)	~1,400	0.03 – 0.05	(2019) (w/o battery storage)[5]
6	Wind (land)	~1,450	0.25 – 0.08	(2019)[6]
7	Nuclear	~6,800	~0.08	(2019)[7]
8	Coal	4,000 – 6,200	~0.09 - ~0.16	(2017) (low = new plant; high = with CCS (carbon capture + storage)[8]
9	Natural Gas	920 – 3,300	~0.06 - ~0.16	(2017) (low = turbine combined cycle; high = same + CCS)[9]
10	Tidal	"high"	0.2 – 0.45	(2020) (~ 535MW in operation worldwide; most 'tidal barrage' (~522MW)[10]
11	Wave	"high"	0.3 – 0.55	(2020) (< 3MW in operation worldwide)[10]

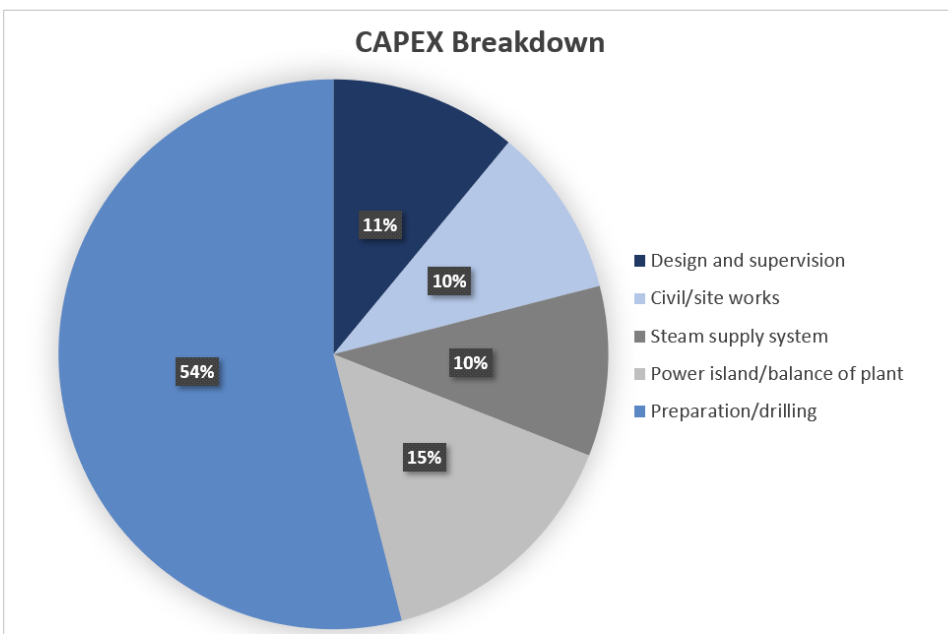
Geothermal plants, like hydroelectric and nuclear plants, are capital-intensive—in the case of near-hydrothermal and deep EGS plants, far more so than wind or solar installations. Therefore, geothermal plants have high up-front financial risk, as even the best planning cannot guarantee a project will come in at the forecasted cost or even be completed. However, as noted earlier, these plants can often be built out incrementally, starting with a small pilot plant (that requires a relatively small initial capital investment) to validate the resource, then scaling up, if and when the site's value is proven. This option is not available with nuclear or hydroelectric plants.

The LCOE estimates also suggest that existing (hydrothermal) geothermal plants are cost-competitive with other forms of electricity generation: substantial up-front capital costs are counterbalanced by the plants' long lifetimes and low operating costs.

Table 3 shows that CAPEX for geothermal plants varies greatly. For hydrothermal reservoirs, based on experience to date, CAPEX can range from 2,400 to 6,200 USD per kW of capacity, depending on the complexity of the site. These figures compare favourably with the CAPEX for hydroelectric, natural gas, or coal-fired power, but they are generally higher than those for solar or wind. CAPEX and therefore LCOE are far higher for EGS, especially deep EGS. But, importantly, the estimates in Table 3 do not incorporate the major advances in drilling technology that this opportunity analysis argues are essential for EGS's wide adoption.

What drives geothermal costs? Even for hydrothermal plants, CAPEX is dominated by drilling and well completion. Indeed, a 2019 analysis by Belyakov[11] of a range of geothermal (primarily hydrothermal) projects estimates that, on average, drilling accounts for 54 percent of all capital costs (Fig. 9).

Figure 9. CAPEX breakdown for geothermal projects
(Based on data from *Belyakov 2019*[6])



Of course, a project's actual cost—and the percentage associated with drilling—will vary widely and be lower for projects with simple geologies requiring shallower drilling and higher for more complex geologies and deeper drilling.

Deep EGS projects have substantially higher CAPEX (by a factor of 3 to 5 or more) than hydrothermal, largely due to the much higher drilling costs. Indeed, modeling work by the US National Renewable Energy Laboratory (NREL) estimates that CAPEX for EGS projects with well depths of 3 to 6 km ranges from about 16,000 USD per kW (if extracting extremely hot, >180°C, fluid) to 35,000 USD per kW (if extracting lower temperature, <150°C, fluid).[12] This estimate does not cover the depths necessary for viable deep EGS in most of Canada and much of the world (~10 km).

If deep EGS is to become a reasonable business proposition, drilling costs must be dramatically reduced. Two main factors drive these costs: the time it takes to drill and complete the well, which boosts time-dependent expenses such as salaries, equipment rental and amortization, and fuel to power the drilling operation; and the costs of materials going into the hole, for instance casing, mud, cement, and tubing, which are largely fixed for a given depth. The principal lever to reduce drilling cost, therefore, is reduction in the time needed to complete the well.

Several analyses suggest that cost increases exponentially with depth.[13] Drilling slows down the deeper you drill for a few reasons. Deeper holes must be wider at the top to support the many casing strings needed further down. Bigger holes take longer to drill and require more tubing and other material inputs. Activities like pulling up and lowering the drill string (called "tripping" in the industry) to replace damaged or worn-out drill bits also take progressively longer as holes get deeper. And lastly, deeper holes typically encounter far harder rock, which can slow drilling by more than an order of magnitude compared to drilling through sedimentary rock; this hard rock also quickly dulls standard drill bits, necessitating more frequent tripping. These issues are particularly acute for deep EGS.

Linear vs. geometric cost scaling

Linear growth of power station cost

Power output from geothermal stations can increase (roughly) linearly with the amount of money invested. That is, doubling investment in an operating plant can double power output. This assumes the geology supports expanding the underground geothermal reservoir and that the new wells are of the same depth or unit cost as the original wells. These factors can largely be verified when the first phase of a plant is built.

Geometric growth of well cost with depth

Well drilling costs grow non-linearly with well depth, because drilling gets slower as wells get deeper—and in drilling, time is money. The nonlinear relationship between cost and well depth is particularly true when drilling through hard (non-sedimentary) rock. Cost-effective ultra-deep geothermal thus requires dramatic reductions in "well completion" costs, via improved hard rock drill bits (for fast drilling) and via improved drilling technologies (e.g., expandable tubing/well casings) that further reduce time and overall cost to completion.

5.2 Environmental risk

Carbon and landscape impacts

As is true for wind, solar, tidal, and hydroelectric power plants, geothermal projects produce zero- or near-zero carbon electricity, depending on whether one counts the GHG emissions associated with manufacturing and installing the system. Construction of zero- or near-zero carbon power plants still requires carbon-intensive materials (e.g., cement, steel, and plastics); the transportation of these materials to the plant site also produces GHG emissions. Yet the GHG emissions associated with building materials and transportation will drop in the coming years, as those sectors electrify.

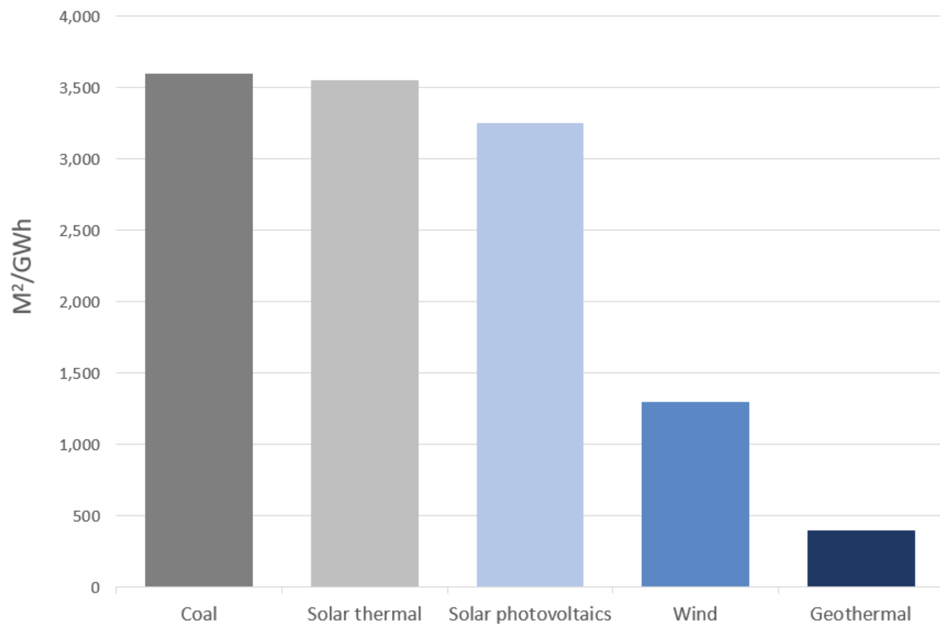
But among zero- or near-zero carbon electricity sources, geothermal is unique in that it requires a particularly carbon-intensive process: drilling. Drilling equipment uses diesel fuel almost exclusively. Although drilling technologies might eventually be decarbonized—Norway, for example, is electrifying drilling operations at some of its large, offshore drilling platforms—the technological hurdles for decarbonizing the operation of mobile, land-based drilling rigs operating in remote areas are extremely high and unlikely to be met soon.

Landscape impact refers to the surface area substantially affected by building and operating a power station. A wind farm, for example, needs land for turbines, cabling, conduits, access roads, and associated buildings. A hydroelectric station needs land for the dam and its supporting infrastructure and for the reservoir behind the dam. Coal or natural gas power stations (and their fuel storage) occupy land and require that other parts of the landscape be excavated or deforested to produce the necessary fuel.

Importantly, geothermal produces *significantly less landscape disturbance* than solar, wind, and hydroelectricity—and thus poses a smaller risk to agricultural and recreational lands and ecosystems. Figure 10 compares the average impact of different electricity sources, adjusted for power station size, to show impact per GWh of generated power. Geothermal projects have the lowest impact per unit of power, because they affect such a small surface area. Horizontal well drilling can allow large reservoirs to be reached using relatively few drilling sites.

Figure 10. Surface land impact of electricity sources

(Reproduced from *DOE 2019*,[14] data from *Kagel at al. 2007*[15])



A key factor influencing how much different energy sources disturb the landscape is the power density—measured in watts generated per square meter of landscape occupied or disturbed—of the underlying energy-production technology. All things being equal, energy sources with higher power densities have a lower impact on the landscape. Table 4 shows that high-temperature geothermal plants rank near the top of the list of zero-carbon energy technologies.

Table 4. Comparative power densities of selected net-zero energy sources

(Data from van Zalk and Behrens 2018[16])

Electricity source	Range of power density (W/m^2)	Mean power density (W/m^2)
Utility-scale PV	4.2 – 7.5	5.8
High-temp geothermal (>250°C)	1.6 – 8.4	4.9
Offshore wind	2.2 – 6.3	4.2
Onshore wind	2.4 – 3.8	3.1
Low-temp geothermal (<250°C)	0.5 – 2.9	1.6
Large hydro	0.2 – 1.0	0.5
Oil crops	N/A	0.2
Wood crops	N/A	0.2

However, estimates of the landscape impacts and power densities of different electricity sources are notoriously unreliable and vary widely from one study to the next. Distinctions between terms like land use, landscape impact, and power density are often unclear. Also, in the case of solar PV, insolation levels—and therefore landscape impact per unit of power generated—vary greatly by latitude.

Table 5 illustrates the wide range of estimates of land impact derived from three recent studies of utility-scale solar PV. The table uses as a comparison baseline the Canadian Energy Regulator's projection of the solar power needed in Canada by 2050 if the country is to reach net zero. Clearly, better estimates of the relative power density and landscape impacts for various electricity sources will help policymakers and the public understand the true costs of those sources and the trade-offs among them.

Table 5. Variability of land impact estimates for utility-scale solar PV

Source	m^2 per GWh	Term	Land required for 78.73 TWh* of solar electricity generation (km^2)	Equivalent area	Notes
Kagel et al. (2007)[17]	3,237	Land use	255	Area of Saskatoon	Used in Figure 10 and the 2018 *GeoVision* report (US)
Ong et al. (2013)[18]	11,331 – 14,973	Land use	892 – 1,179	Area of Calgary	2.8 – 3.7 acres/GWh (US)
Capellán-Pérez et al. (2017)[19]	38,051 - 57,077	Power density	2,996 - 4,494	Area of metro Vancouver	Figure converted from 2.5 W/m^2 (Canada's estimated average solar power density)

*78.73 TWh is the projection for 2050 solar electricity generation in CER (2021).[20]

The three main environmental concerns associated with geothermal projects are aquifer contamination, water use, and induced seismicity.

Aquifer contamination

Drilling beneath the surface of Earth risks contaminating underground water aquifers with chemicals associated with the drilling process. Aquifers are natural underground reservoirs created over time by surface water runoff; they often serve as water sources for local populations. Aquifer contamination can have enormous, potentially irreversible negative impacts on human health, local agriculture, or the ecosystem.

There are many ways to pollute an aquifer. Possibilities include leakage from surface waste (e.g., from construction debris saturated with rainfall), leakage of contaminated fluid from cooling or mud ponds, discharge of waste fluid, or leakage from wells and pipelines. Leaking wells are a particular concern for geothermal power stations, because geothermal fluids are laden with toxic salts, minerals, and dissolved gases. If a geothermal well or pipeline carrying fluid from a well to the power station leaks, the fluid could contaminate the surface or flow through porous rock into an underground aquifer.

For these reasons, great care must be taken in drilling, well completion, and ongoing monitoring to ensure wells are both constructed not to leak and continuously monitored to detect and control leaks if and when they happen.

Water consumption

During construction, EGS power stations require water to stimulate (create) and then fill the EGS reservoir. This water becomes the geothermal hot working fluid, pumped in a continuous loop up from the reservoir to power the turbines and then back into the EGS reservoir to be reheated.

Ideally once the reservoir is filled, it never needs to be refilled. In practice, however, the reservoir may need to be replenished from time to time to account for fluid lost from the EGS reservoir (e.g., due to percolation into the surrounding rock or other loss mechanisms). Averaged over the lifetime of a station, however, the water needed to "top up" the reservoir should be negligible: if an EGS reservoir requires continuous and substantial replenishment, it is likely suffering from a structural problem that will make its operation uneconomical. Thus "reservoir water consumption" should be minimal once the system is up and running.

EGS power stations may also need a continuous supply of cool water to cool the turbines. To improve energy conversion efficiency, all thermal power stations (fossil fuel, nuclear, and geothermal) can benefit from cooling the working fluid leaving the final-stage turbine. These stations are often located near large water sources (oceans, rivers, or lakes) and use heat exchangers to transfer heat from the fluid to the local water. Provided the water source is very large, the heated water has only a small environmental impact. But excessive heating of smaller bodies of water can be harmful to aquatic ecosystems.[21]

One alternative is "dry cooling," whereby the power station's working fluid passes through a heat exchanger to transfer heat to a second fluid (again, perhaps water), but the temperature of this second fluid is lowered with cooling towers (essentially big radiators) that transfer the heat to the atmosphere without fluid loss. The dry cooling option is less efficient, so less electrical power is produced. But it has the advantage that only small amounts of water are needed to initially "charge" (and occasional recharge) the system.

Induced seismicity

Oil and gas fracking involves temporarily injecting fluid under high pressure into oil- or gas-rich pockets in the rock to stimulate production; the fluid is then withdrawn to let the oil or gas flow. The large quantities of waste fluid are then discarded by injection into deep geological formations. These activities, particularly waste storage, can sometimes induce local seismic activity and earthquakes.[22]

Creating and operating an EGS reservoir is functionally similar to oil and gas fracking, so it can also lead to seismic activity. Reservoir construction involves injecting high-pressure fluid into a rock formation, creating stress in the rock. The injected fluid can also change the elastic properties of the rock—that is, how easily the rock bends or fractures—making it easier for the rock to shear or otherwise deform. Thus, even if the rock used to construct the reservoir is not initially under stress, the reservoir stimulation process can create stress. After (or even during) stimulation, the rock may shear or otherwise deform to reduce the added stress, leading to one or more small seismic events.

In a simplified "zero starting stress" scenario, rock deformation is largely constrained to the rock inside the stimulated reservoir, in which case the magnitude of stress release can be roughly modeled. Such modeling indicates seismic events will be small.[23] Given that reservoirs are several kilometers below the surface, the seismic activity at the surface will be even smaller and detectable only by seismometers. At geothermal sites with such conditions, plant operators have observed earthquakes only of magnitudes less than 2.5 on the Richter scale, which are too small to be felt by local residents.[18]

However, the rock surrounding most of today's potential EGS reservoirs is already under stress. Shallow EGS requires hot rock close to the surface. Such sites are usually near tectonic boundaries, where the plates are thin, pressing against each other, and therefore deformed. In such cases, creating and operating a reservoir can trigger the release of the pre-existing stress in the reservoir and surrounding rock, leading to larger seismic events and earthquakes easily felt at the surface.

Indeed, several recent shallow EGS projects have been halted due to seismicity, including projects near Basel, Switzerland in 2006 (which stimulated a magnitude 3.4 earthquake),[24] Pohang, Korea in 2017 (a magnitude 5.5 earthquake),[25] and Strasbourg, France in 2021 (a magnitude 3.9 earthquake).[26] These projects were stopped mainly because the pilot sites were close to large towns or cities, so that even small earthquakes posed large financial and human safety risks. Seismic risk is less of a concern for sites far from heavily populated areas. For example, the Geysers hydrothermal station in California has caused a number of earthquakes up to a magnitude of 4.5, but it is far enough from large population centers (about 120 km north of San Francisco and 100 km west of Sacramento) not to pose a significant risk.[27]

In 2008, the International Energy Agency (IEA) developed a protocol for addressing concerns around induced seismicity, which was subsequently updated by the US Department of Energy in 2012 to help operators, regulators, governments, and local communities address this risk arising from EGS projects.[28]

Current EGS projects and advances in seismic analysis and test drilling will help scientists and engineers understand why such seismic events happen and how they can be better predicted and mitigated. Earthquake risk can never be completely eliminated, but improving our understanding of pre-existing seismic stresses and of how EGS reservoir stimulation and operation cause seismic events will help refine protocols and reduce event size.

Deep EGS reservoirs will likely be seismically safer (at the surface) than shallow reservoirs, for two reasons. First, deep EGS creates geothermal opportunities in regions far away from plate boundaries and in geologies where the intrinsic stress in the deep rock should be lower. Second, it is well known that the strength of surface shaking from an earthquake decreases with distance—both horizontally and vertically—from the earthquake's source. All things being equal, seismic events from a deep EGS reservoir 10 km down should be less significant at the surface than those from a same-sized event in a reservoir 5 km down.

These hypotheses still need to be tested. If they hold true, deep EGS projects will have the additional advantage of posing less of a seismic risk than hydrothermal and shallow EGS projects.

Interestingly, hydroelectric power stations can also induce earthquakes, due to the huge mass introduced when a large new reservoir is filled. This risk stems from the fact that the geography that yields good hydroelectric sites (deep valleys and steep gradients to build a deep reservoir) often coincides with regions of plate uplift and significant rock stress.

Climate change vulnerabilities

Power stations are large infrastructure projects that are expected to operate for many decades—often half a century or more. So they should be built to withstand the growing impacts of climate change, especially of extreme weather events like floods, droughts (and their associated wildfires), and windstorms (including cyclones and tornados). Because a significant component of the geothermal power-generation process occurs underground, the technology is uniquely insulated from such dangers.

Hydroelectric: Dependence on stable and predictable precipitation patterns and temperatures. Hydroelectric power stations are vulnerable to reductions in precipitation and increases in temperature that reduce water accumulation in the reservoir. These challenges are already threatening the power-generation capacity of the Hoover Dam and many other hydroelectric stations in the western United States.[29] Conversely, much higher than anticipated rainfall can lead to flows that exceed the “overflow” capacity of the dam and spillways, putting strain on the system and potentially requiring extensive re-engineering of the dam and reservoir. Extreme storms can also cause landslides and washouts that damage vital hydroelectric infrastructure.

Wind: Dependence on stable and predictable wind patterns. The delivery commitments of wind electricity depend on predictable seasonal wind directions and wind speeds. Climate change is affecting the intensity, direction, and variability of winds around the world. Such impacts have already been seen in the UK, where unexpectedly calm North Sea winds in the fall of 2021 led to a major shortfall in wind electricity.[30,31]

Solar: Dependence on stable surface irradiance (cloud cover) patterns and vulnerability to extreme wind events. Solar power generation capacity may increase in some areas, if climate change leads to hotter temperatures and clearer skies. In other regions, though, climate change will produce more days of cloud cover. Such impacts were seen in Germany in the spring and summer of 2021, when unexpected weather conditions led to shortfalls in anticipated solar power generation.[32,33] Large solar arrays—with their hectares of wide, flat, light solar panels—are also susceptible to damage by extreme weather events, especially hailstorms.

Geothermal/coal/natural gas/nuclear: Dependence on stable precipitation patterns and temperatures. All thermal power stations depend on access to abundant cool water and are therefore vulnerable to changes in precipitation and increases in temperature that reduce water accumulation (and increase water temperatures) in nearby sources. Stations that use "dry" cooling to address such problems will become less efficient as ambient air temperatures rise.

Notes

[1] Cost ranges can be due to site location/size and project complexity (e.g., for geothermal a "binary cycle" is more expensive than a "flash" plant).

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[12] Lower temperatures lead to higher unit costs for two reasons. First, lower temperatures require that more wells be drilled, or substantially higher fluid flow sustained, to extract the same amount of "usable" thermal energy. (Recall that lower temperatures entail lower efficiency in the conversion of heat to electricity.) Second, lower temperatures call for more expensive binary cycle power generators to extract as much electricity as possible from the lower-temperature resource. National Renewable Energy Lab (NREL). (2019). "Annual Technology Baseline: Electricity (Geothermal)." *NREL.* https://atb-archive.nrel.gov/electricity/2019/index.html?t=gt.

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6. Financing obstacles and social benefits

Key messages:

- High R&D and up-front costs (in particular, for deep drilling) remain the most significant barrier to the development and widespread deployment of deep EGS.
- Research and development that extends the life of deep EGS wells can also support long-term financing mechanisms; these mechanisms can, in turn, increase the financial viability of deep EGS projects in general.
- The Canadian federal government's support of nuclear power development provides a precedent and a model.
- Once deep EGS is cost-competitive, 50- or 100-year "GeoBonds"—modelled on Victory Bonds during WWI and WWII and backed by Canadian federal and provincial governments—are a potential tool for long-term financing of the technology's widespread deployment.
- A major program to develop deep EGS in Canada could contribute to national solidarity around climate action, by supporting soon-to-be displaced workers and industries in provinces highly dependent on the oil and gas sectors, without directly competing with those sectors.

6.1 Financing

Research and development

As discussed earlier, R&D and up-front costs present a barrier to the adoption of deep EGS as a major energy source—and potential technology export—for Canada. The R&D phase of deep EGS is inherently risky. Accordingly, financing this phase will not be attractive to institutional investors like pension funds, which hold a significant proportion of Canada's investible assets, nor will it be attractive to the major banks. Investors who might be more comfortable with high-risk, early-stage financing in general are equally unlikely to contribute to early financing of deep EGS, as the scale required would be much too large, even for investor syndicates. Government support is necessary.

The form of government support could evolve as deep EGS technology develops. Straightforward government R&D funding is required at the earliest stages. It could entail establishment of a research, development, and commercialization institute—potentially as part of an existing government department—that hires technical experts to get demonstration projects off the ground, perform feasibility studies, and conduct analyses on the amount of funding required to help deep EGS reach the commercialization stage. This entity would carry out some of its own drilling experiments and issue grants to external partners in exchange for equity stakes and access to open-source intellectual property/patents. The Canadian government could even purchase existing patents and provide open-source access, as Tesla has famously done.[1]

There is a precedent for government taking the lead in R&D financing in Canada. Nuclear power development was almost entirely funded by the federal government,[2] and the technology remains Canada's largest source of low-carbon energy after hydro power.[3] From 1952 to 1993, the Canadian government invested 7.5 billion CAD (in 2020 dollars) in nuclear power R&D through Atomic Energy of Canada Limited (AECL), a Crown Corporation. In total, the government spent nearly CAD 17 billion (in 2020 dollars) on Canada's nuclear program from 1952 to 2006.[4] For decades, the resulting CANDU reactors were sold around the world—18 are now located in Canada and a further 10 in other countries.[5] The AECL is a Crown Corporation that reports to Parliament through the Minister of Natural Resources, a potential model for a deep EGS Crown Corporation during and after the R&D stage.

Commercialization

After the pure R&D stage, a Canadian federal Crown Corporation—again, perhaps constituted along the lines of AECL—could help ramp up *public* commercialization of deep EGS while, at the same time, taking 51 percent stakes in *private* ventures. The Business Development Bank of Canada (BDC), itself a Crown Corporation, is a potential model, as it currently makes equity investments in Canadian companies at the venture-capital stage.

Once the costs of deep EGS have fallen enough that projects are of potential interest to professional investors, the government could set up a Canadian green investment bank to invest in scaling up deep EGS and to take over the new deep EGS Crown Corporation's investments and/or BDC's green venture-capital investments. Such a bank could expand financing of worthwhile green technologies in general, while boosting the scale and capability of the Canadian Infrastructure Bank's (CIB) climate spending.[6]

At this stage, a Canadian green investment bank (or an expanded green division of the CIB) would do well to replicate the success of the commercialization of offshore wind in the UK. There, the national Green Investment Bank hired specialists to undertake due diligence of offshore wind projects and otherwise compile the documentation necessary to de-risk such investments for professional investors.[7] In the UK, this approach so lowered the cost of offshore wind that, within just a few years, it could compete with other sources of electricity.

With this federal facilitation, Canadian provincial governments could further support deep EGS commercialization with offtake contracts—agreements to purchase future deep EGS electricity that provide assurance for investors and help secure up-front investments in plant development. Utilities would be guaranteed a certain flow and price of electricity—say, through a 60-year power purchase agreement—produced by the first several demonstration projects. Provinces could also establish a time-limited framework of feed-in tariffs or other subsidy mechanisms, until deep EGS's cost becomes competitive with that of other electricity sources.

Specialists hired by the green investment bank could consult with Canada's public pension funds and other institutional investors to ensure that the financing meets investors' specifications. Fortunately, deep EGS projects—once investable—would match pension fund liabilities quite well, because they would provide long-term, reliable cash flows. If required at commercialization, the government could issue a government guarantee for debt financing to lower the risk for pension funds, credit unions, banks, and insurance companies. Among other benefits, such guarantees would ensure that pension funds could invest in deep EGS without violating their statutory responsibilities to beneficiaries.

Scaling up

Once cost-competitive, deep EGS would need financing for scaling up. Because Canada's pension funds are unusually concentrated—several of them are among the largest in the world—they could potentially deploy billions in scale-up financing.

Scaling up could also involve investments from Canadian residents via *GeoBonds*, modeled after Victory Bonds in WWI and WWII. Canada used these bonds to raise billions from individuals, families, businesses, and organizations; they were effectively war loans to the government that were meant to keep inflation down and tie the public to the war effort.[8,9] By any standard, the initiative was a success: War Savings Certificates went on the market in May 1940 and were sold door-to-door by volunteers as well as banks, post offices, trust companies, and other authorized dealers. They yielded 12.5 billion USD—or about 550 USD (1940) per capita—covering fully half of Canada's war costs.[10]

GeoBonds could usefully invoke the historical success of Victory Bonds in Canada, with the same widespread accessibility and participation amongst a broad swath of the population. As with Victory Bonds, GeoBonds would connect the Canadian public to the goal of energy diversification and decarbonization. They could also be designed as convertible debt: once a particular threshold is breached—say, a specified level of profitability and/or indebtedness—the bonds would convert to stocks, allowing Canadian residents to share in the profits of deep EGS through ownership stakes.

Advantages in deep EGS financing

As discussed in Section 3.5, geothermal wells can and should be built for a longer lifespan than typical of the oil and gas industry. Oil and gas wells naturally run down within 20 years or so, whereas the average life of geothermal wells should be longer and extended as much as possible. Therefore, R&D for deep EGS should focus on the longevity of well components, and this sort of R&D is unlikely to be undertaken by oil and gas specialists whose aim is to tap a well's potential more quickly. But the longer timeline also presents advantages for deep EGS financing: if high up-front costs can be paid off over a longer time period, LCOE will be lower and deep EGS will compete more easily with other forms of electricity production.

The corollary is that the issuance of a 50- or even 100-year GeoBond by the Canadian government would match the actual period in which the project(s) would pay back the original cost. Long-term debt financing is common for other types of long-lived electricity-generating infrastructure. Hydroelectric dams, for instance, can have lifespans of a century or more, with the possibility of extension through upgrades and maintenance,[11] so their debt can reasonably be issued for 50-year terms.[12]

If Canada develops retrofitting capabilities/programs for older geothermal projects, well lifespan could be extended well beyond 100 years, even indefinitely, or at least long enough that financing becomes a negligible concern, and OPEX, which for geothermal is relatively low, becomes the central point of comparison with other forms of power production. Then, on a LCOE basis, deep EGS is more than competitive with other electricity sources. Accordingly, after the R&D stage, financing should exploit the advantage of the long-term resilience of deep EGS infrastructure.

Geothermal electricity is particularly valuable as baseload power. Its value as dispatchable power to balance the grid and complement intermittent electricity generated by solar and wind is slightly lower for Canadian provinces with significant hydroelectric capacity. But deep EGS's dispatchability will increase in importance as Canadian electricity demand rises sharply in the coming years and as intermittent sources become larger components of the overall supply mix.[13]

Provinces without significant hydro or nuclear resources will immediately benefit from cost-effective geothermal power. So will other wealthy northern hemisphere countries, especially those whose energy use rises in the winter when insolation (and therefore PV solar output) wanes. Were Canada to become a geothermal superpower, the benefit would not be limited to securing a growing share of the global electricity (and heating) market. Canada would also reap scale effects as the technology advances down the marginal cost curve, which would lower the domestic cost of baseload, dispatchable, and seasonal power. In short, deep EGS helps fill critical gaps in a decarbonizing grid.

6.2 Socio-economic benefits

Regionalism is a longstanding feature of Canadian culture and politics. Attitudes towards climate change and towards extractive industries vary greatly across the country. The provinces with the highest proportion of workers in the oil and gas industry—and with the greatest reliance on fossil fuel-derived electricity—also have among the highest levels of unemployment:

- Oil production is concentrated in Alberta, Saskatchewan, and Newfoundland and Labrador,[14] while natural gas production is concentrated in Alberta, British Columbia, and Saskatchewan.[15]
- Three provinces and one territory produce a large majority (>70 percent) of their electricity from hydrocarbons (coal, gas, and petroleum): Alberta, Saskatchewan, Nova Scotia, and Nunavut.[16]

- Alberta, Nova Scotia, and Nunavut all have higher-than-average unemployment rates (ranging from 9.6 percent to 14 percent), with Saskatchewan below the Canadian average but at a near-historic provincial high of 8.3 percent.[17]

Because of the concentration in these provinces of relevant skills, unemployed workers, and carbon-intensive electricity sources, governments should prioritize pilot projects in Alberta, Saskatchewan, Nunavut, Newfoundland and Labrador, and Nova Scotia, with a particular focus on Alberta and Saskatchewan. This strategy will align deep EGS investment with the geographic distribution of needs and skills, while potentially contributing to national solidarity around climate action. Deep EGS would not compete directly with Canada's oil production. It would instead put skilled workers to good use while interfering little with traditional employment in the oil and gas sector.

Otherwise, going forward, employment in the oil and gas sector is forecasted to fall dramatically. A TD Bank report estimates that "between 50-75 percent of those workers are at risk of displacement in the transition through 2050, equivalent to 312,000 to 450,000 workers."[18] Scaling up deep EGS in Canada would help support some of these workers by providing a viable employment path that leverages existing skills.

Moreover, this labor shift converts a liability into an asset on the path to decarbonization. Most green technology subsectors lack skilled workers,[19] but in the case of deep EGS, there is a surfeit of workers with relevant skills—in drilling, subsurface geology, well and power plant engineering, operation of heavy machinery, and more. Deep EGS could deploy these workers' skills in the provinces with the greatest source of sector-appropriate unemployed workers—provinces that, serendipitously, are also the places where clean electricity is most needed.

Creating a viable deep EGS industrial capability could have a wide range of benefits to Canada—from delivering domestic geothermal power capacity to creating Canadian engineering leaders able to develop and deploy such expertise and infrastructure worldwide. A comprehensive employment analysis is needed to better understand the extent to which deep EGS can offset unemployment in the oil and gas sector and tap into international markets. This employment analysis is one of the key next steps highlighted in Section 7.2.

6.3 Additional uses of geothermal energy

This report focuses on relatively near-term geothermal power-generation opportunities that exploit underground temperatures <350°C. But depending on depth and local geology, deep geothermal wells can in principle access reservoirs with temperatures well above 500°C. Such "high-T resources" could provide the heat needed for hard-to-decarbonize industrial processes such as cement manufacturing, hydrogen production, and metallurgical processing, dramatically expanding the opportunity space for geothermal energy.

Drilling has already proven such high-T resources are accessible. The DESCRAMBLE research project, which conducted test drilling in the Larderello geothermal field in Italy, achieved bottom hole temperatures (at 2.9 km) over 500°C.[20] Even higher temperatures are certainly possible, but much work is needed—to develop extreme-temperature drilling technology, achieve drilling cost reductions, and invent methods to bring the high temperatures to the surface—to turn deep EGS into an economically viable option for producing high-T industrial heat. Appendix 6 lists some key commodities and their processing heat requirements.

Such a technological advance could help Canada, which currently exports large quantities of unrefined metals, refine domestic iron ore and aluminum, for example, and capture all the economic benefits a full production chain entails. Indeed, transformative improvements in technology, or low-cost access to new sources of energy, often yield unexpected industrial and business opportunities. For example, the development of drill bits for digging quickly and cheaply through hard rock could make it easier to identify reserves of critical minerals such as lithium, nickel, cobalt, manganese, and graphite for batteries and other green technologies. If deep EGS were used in the production of green hydrogen, it could enable zero-carbon propulsion of heavy vehicles and shipping. Finally, if geothermal electricity could power the production of hydrocarbons from atmospheric carbon, it could provide a stream of carbon-neutral fuel for the aviation sector.[21] Deep EGS could, therefore, ultimately address large portion of the world's decarbonization challenges.

The full-scale development of deep EGS will require broad geographical surveys to determine suitable locations for drilling. Since oil, gas, metal, and mineral deposits are often commercially viable upon discovery, some might be concerned that these geographical surveys themselves could lead to the exploitation of new oil and gas reserves, with attendant environmental consequences. But it is exceedingly unlikely that the discovery of new oil and gas reserves—particularly those located 5 km or more beneath Earth's surface—would lead to an increase in oil and gas production or trigger the development of new fossil-fuel infrastructure. Existing and already proven reserves are economically viable with current drilling technology and exceed the world's remaining carbon budget.[22] Indeed, if oil and gas companies saw value in developing deep EGS drilling technologies for the extraction of hydrocarbon resources, this technology would likely already exist.

Notes

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7. Conclusion: An agenda for R&D, investment, and policy

7.1 Audacious goals

This opportunity analysis makes the case for placing a large R&D bet on deep EGS—a critical technology that is currently missing from the toolkit Canada is developing to address the country's net-zero electricity gap. To fully exploit the deep EGS opportunity, we argue, governments, industry players, investors, and researchers must coordinate their efforts to overcome several formidable R&D challenges, stimulate investment, and develop supportive policies and regulations.

We frame this deep EGS agenda by specifying several "audacious goals." Although any such goals will almost certainly be revised as research advances, stating them explicitly nonetheless helps provide clear benchmarks for measuring success and helps focus the efforts of people, governments, agencies, and firms.

Technological goals

- Drill commercial quality geothermal wells to a depth of 10 km through hard rock, achieving a bottom hole temperature of at least 250°C, for <$10 million/well.
- Create functional, economically viable EGS reservoirs at depths of up to 10 km at commercially feasible cost.
- Build geothermal wells with a practical lifetime of over 75 years.

Business goals

- Create a world-leading Canadian capacity to design, build, and operate deep EGS plants in Canada and internationally.
- Ensure the IP from this industry remains a Canadian asset, through Canadian crown corporations and/or public stakes in private Canadian-owned corporations.

7.2 Research and commercialization gaps: Recommendations and key questions

To achieve the above goals, we recommend the following actions, disaggregated by the main stages of deep EGS R&D and commercialization. For each recommendation, we identify specific questions that must be addressed for success.

Planning and exploration

Gather high-quality geological data relevant for deep EGS for most regions of Canada—particularly the Canadian Shield and central and eastern Canada.

- What is the scale and distribution of the Canadian deep EGS opportunity?
- What well depths are necessary to reach hot rock in different regions?

Create a national agency to facilitate data aggregation and knowledge exchange for deep EGS.

- What is the ideal institutional design for facilitating Canadian data aggregation and knowledge exchange for deep EGS?

Improve exploration success rates to lower exploration costs.

- What advances in remote sensing technology, subsurface geochemistry, and field geophysics are on the horizon? Which are the most promising?

Drilling

Gather data about the costs and risks associated with existing technologies for hard rock drilling.

- What is the precise "cost per km" for hard rock drilling with current technologies?
- What proportion of that drilling cost is associated with "materials" (e.g., casing, mud, cement, tubing, etc.)?
- What is the "carbon cost" associated with hard rock drilling?
- What are the risks of induced seismicity at various depths and in various geological contexts?

Gather information and data about current efforts to decarbonize drilling.

- What companies or projects (if any) are developing technologies for low- or no-carbon drilling?
- What is the "energy return on energy investment" (EROEI) associated with deep drilling?

Analyze the cost competitiveness of deep EGS in different energy market and regulatory scenarios.

- What are the deep EGS cost-per-well targets in various energy market and regulatory scenarios (e.g., with the removal of subsidies for fossil fuels)?
- What are the deep EGS cost-per-well targets for various working fluid temperatures and flow rates?

Improve drilling and well completion technology and techniques to lower costs.

- What advances in percussive, water-jet, plasma, and other drilling technologies are on the horizon? Which are the most promising?
- Are there any R&D projects that focus on reducing the time needed for drill replacement or address other cost improvement factors (e.g., expandable tubing)?

Reservoir construction

Improve reservoir construction techniques to ensure reliability and prevent leakage at well depths over 5 km.

- To what extent can existing reservoir creation techniques be applied to deep EGS?
- What is the potential for new techniques, like closed loops (for example, as used by the Canadian firm Eavor) and "hydroshearing," to benefit deep EGS?
- Are the risks associated with EGS hydraulic fracturing comparable to those arising from oil and gas fracking (e.g., leakage of toxic salts, minerals, and dissolved gases)?
- What key variables affect the rate of geothermal reservoir heat depletion, and how can this depletion be mitigated?

Investment and finance

Analyze the optimal level of investment to stimulate a breakthrough in deep EGS.

- What is the level of investment necessary to stimulate a rapid improvement in: (1) hard rock drilling technologies; (2) well-completion materials and technologies; and (3) reservoir construction technologies?
- Where should investments be prioritized and how should they be structured?

Improve estimates of costs associated with deep EGS.

- What is the longest-lived geothermal project to date? What does "upkeep" look like (e.g., new wells, replenishing the heat source, etc.)?
- What is the levelized cost of electricity (LCOE) for a deep EGS power plant with a 50/75/100-year lifespan?
- What are accurate power density measurements for deep EGS, conventional hydrothermal, solar, wind, hydro, nuclear, and natural gas power plants?

Create an overarching R&D and investment strategy for Canadian governments and grant-making agencies.

- What are the respective roles of the federal and provincial governments, industry, investors, academia, and other stakeholders in articulating and executing a Canada-wide agenda for deep EGS R&D, investment, and policy?

Develop 50- or 100-year "GeoBonds" backed by the Canadian federal and provincial governments as a tool for long-term debt financing.

- Can the lifespan of deep EGS wells be extended (affordably) beyond 50 years?

Assess the feasibility of establishing a Canadian federal Crown Corporation to lead early-stage R&D and public commercialization of deep EGS.

- To what extent can Atomic Energy of Canada Limited (AECL) and the Business Development Bank of Canada (BDC) serve as potential models?

Assess the feasibility of establishing a Canadian "green investment bank" that can de-risk deep EGS investments and coordinate private commercialization.

- To what extent can the UK's Green Investment Bank serve as a potential model?
- Could these de-risking and coordination tasks be carried out by an expanded green division of the Canadian Infrastructure Bank (CIB)?

Conduct an employment analysis.

- How many jobs (and what types of jobs) can be created by a Canadian deep EGS industry?
- To what extent can existing oil and gas sector workers transition to geothermal jobs?
- How many jobs could a Canadian deep EGS industry eliminate in other sectors?

Assess the size of export markets for Canadian geothermal technologies and expertise.

- What is the total opportunity associated with exporting Canadian geothermal technologies and expertise?
- What countries provide the greatest opportunities for Canadian exports?
- Is Canada's relative advantage in oil and gas *financing* (on Bay Street) relevant/transferrable to deep EGS? Or is Canadian expertise in mining finance more relevant?

Map the intellectual property landscape.

- What key intellectual property exists that is relevant to deep EGS and who owns it?
- What potential models for intellectual property would maximize innovation and incentives for investment?

7.3 Building a deep EGS "Community of Intent"

Over the next months, this analysis will serve as the foundation for a series of dialogues with various Canadian stakeholders from government, industry, finance, and academia. The Cascade Institute aims to build a broad and diverse **Community of Intent** with a shared interest in transforming Canada into the global leader in deep EGS. The goal of the dialogues is to construct a detailed map of the network of relevant stakeholders and to achieve a consensus on:

- the scope and magnitude of the opportunity;
- the key R&D gaps;
- the most significant obstacles to deep EGS R&D, investment, and policy;
- a portfolio of possible strategies and solutions for overcoming these obstacles; and
- the most effective governance structure for coordinating and incentivizing a deep EGS "innovation ecosystem."

Emerging from these dialogues, the Community of Intent will have a clear vision for how federal and provincial governments, industry, investors, academia, and other stakeholders can collaborate in articulating and executing a Canada-wide agenda for deep EGS R&D, investment, and policy. The nature of this public-private innovation ecosystem will evolve based on our understanding of R&D, investment, and policy obstacles and will need to be negotiated among the stakeholders themselves.

The Community of Intent will also need to chart a strategic "R&D pathway" between the current state of drilling and geothermal technology and a world where viable deep EGS can compete at scale. This pathway could involve an initial focus on remote northern communities—where higher-cost geothermal electricity can compete more easily—using pilot projects there to drive costs down. An effective R&D pathway must also navigate the intellectual property landscape and protect the nascent Canadian deep EGS industry from predatory competition originating outside Canada, while delivering economic benefits to the Canadian public.

Appendix 1. Measurement of energy and power

People often use the words energy and power interchangeably, but these terms mean different things.

Energy refers to the energy required to do a defined amount of work. For example, it takes a specific amount of energy to lift a weight a given distance against the force of gravity, or it takes a specific amount of energy to bring 1 litre of water to a boil at room temperature and sea-level pressure.

Energy is commonly measured in *joules*. For example, it takes 1 joule of energy to raise a 1 kg of mass 10.2 cm against the force of Earth's gravity. For various historical reasons, another energy unit, known as the *British thermal unit*, or *BTU* is often used to measure thermal energy, such as the energy produced by burning coal or natural gas. The BTU is defined in terms of heating: it takes 1 BTU of energy to raise the temperature of 1 lb of water by 1 degree Fahrenheit. 1 BTU is equal to approximately 1,055 joules.

Meanwhile, *power* is the *rate* at which energy is being moved or used (an amount of energy per second). The *watt* (abbreviated by a capital "W") is the most common unit of power, defined as 1 joule per second. Thus, the label "100 watts" on a light bulb means the bulb consumes 100 joules of electrical energy per second to stay continuously lit.

Electrical generation stations generate huge amounts of power, so it is common to use much larger units, such as kilowatts (kW), megawatts (MW), and gigawatts (GW) to characterize the size of a station or the maximum capacity of a power line or electrical grid.

Also, the electricity sector does not use the joule as its unit of energy but instead the *watt-hour* (abbreviated Wh): 1 watt-hour is defined as the amount of energy delivered by a 1-watt power source running for one hour. By definition, 1 watt-hour equals 3600 Joules (1 joule / second x 60 seconds / min x 60 mins / hour). As with power (watts), amounts of energy are usually quoted using larger units such as GWh, MWh or kWh. The latter is familiar to almost everyone from the "electricity used" summary on their monthly electric bill.

With thermal power stations there are often two power measures of interest: the peak thermal power produced by the burning of fuel and the peak electrical power produced once the thermal power is converted to electrical power. The former is called *megawatts thermal*, abbreviated MWt (the "t" meaning thermal) and the latter *megawatts electric*, or Mwe ("e" for electricity). The ratio of these two values (Mwe/MWt) is a rough estimate of the thermal efficiency of the station.

Appendix 2. Power station characteristics

Electricity networks largely do not care where the electricity comes from, but they do care about key *attributes* of the power a station provides—namely, whether it is predictable (in amount and when it will be available) and whether it can be provided quickly if demand rises (i.e., whether it can be "ramped up" when additional power is needed). As a result, the sources of electrical power tend to be classified according to three non-exclusive attributes:

Baseload power is power that can be provided continuously at a predictable level for a predictable period of time (e.g., for weeks at a time, with planned maintenance/down times). Baseload power is the most important type of power for a grid operator (the organization managing the power grid that distributes electrical power from producers to consumers). Every other management decision is based on knowing the available baseload.

Dispatchable power is power that can quickly (ideally, in minutes or seconds) flow into the network when requested by the grid operator. Dispatchable power allows the grid to handle situations in which a baseload station unexpectedly shuts down, a grid section fails, or there is an unexpected rise in demand. Nuclear and coal power generation are not considered dispatchable, since they typically take hours to start up. Natural gas plants are sometimes considered dispatchable, because modern plants can have minutes-long start-up times. Hydroelectric and geothermal can also provide dispatchable power as they can also "turn on" quickly.

Intermittent power is power whose availability fluctuates due to the way it is generated. Solar, wind, and wave power fall into this category since they depend on sunlight, wind speed/direction, or wave height. A grid can still use intermittent power but must balance across multiple intermittent suppliers in different geographical regions to ensure overall grid stability—and have sufficient dispatchable power on hand should gaps arise. Intermittent power stations can be combined with energy storage capabilities to essentially serve as "dispatchable plants." For example, solar thermal plants can store some (or all) of the heat they generate in a thermal reservoir and then retrieve it after the sun has set to run a thermal generator.

Black start capability. A black start is the process of restoring a power station or a portion of an electrical grid to operation without drawing power from elsewhere in the grid. In the case of major grid failure, engineers need to "bootstrap" the grid to life, beginning with baseload-capable dispatchable power stations with black start capability. Most thermal or nuclear plants do not have black start capabilities, as they must draw substantial amounts of power to start from scratch. Enabling this capability locally adds substantial cost to the plant (massive diesel generators, more complex power control systems, etc.). Good candidates for black starts are hydroelectric, some gas turbine stations, geothermal, and (potentially) large-scale battery storage.

Today's power grids are robust and reliable in part because only a small portion of power comes from intermittent sources, such as wind or solar. As the amount of intermittent power becomes significant relative to the total baseload, the overall grid and mix of power generation stations need to be substantially upgraded/redesigned to ensure reliable power redistribution and delivery.

Appendix 3. Estimating accessible geothermal energy

Estimated geothermal potential in the US

The best data on potentially extractable geothermal energy come from the United States. Table 6 shows estimates from an Idaho National Laboratory (INL) report published in 2006 by MIT of the amount of geothermal energy beneath the continental US at depths up to 10 km.[1]

Table 6. Estimated US geothermal resource base to 10 km depth by category
(Adapted from *INL 2006*[1])

Category of resource	Geothermal energy, in exajoules (1 EJ = 10^{18} J)
Conduction-dominated EGS	
Sedimentary rock formations	100,000
Crystalline basement rock formations	13,300,000
Supercritical volcanic EGS*	74,100
Hydrothermal	2,400 – 9,600
Coproduced fluids	0.0944 – 0.4510
Geopressured systems	46,000 – 110,000

* Excludes Yellowstone National Park and Hawaii

The INL report's data on "sedimentary rock formations" and "supercritical volcanic EGS" roughly correspond with what we call shallow EGS, while "crystalline basement rock formations" correspond with deep EGS. We transpose their estimates into our categories in Table 7, which summarizes the relative amount of geothermal energy that could theoretically be reached by different systems.

Table 7. Estimated US geothermal resource base to 10 km depth by type of geothermal system

Type of geothermal system	Thermal energy, in exajoules (1 EJ = 10^{18} J)	Percentage of total
Hydrothermal	10,000	< 0.1%
Shallow EGS	175,000	1.3%
Deep EGS	13,300,000	98.6%
All EGS	14,000,000	>99.9%

However, only a small amount of the total geothermal resource base can be usefully extracted, because much of the thermal energy is either too cool to be useful or is located below protected or urban areas.[1] Further, a significant portion of the resource must remain in the ground so that the level of thermal energy withdrawal can be sustained over time (i.e., so that heat is not withdrawn faster than it can be "recharged" from below). Due to these limitations, the INL report conservatively estimates that only 2 percent of the total geothermal resource base can be sustainably extracted. Therefore, the amount of recoverable energy from "all EGS" is approximately 2.8×10^5 EJ (compared with the theoretical total of 1.4×10^7 EJ)—a significantly smaller number.

In Table 8, we proportionally rescale the extractable energy for each geothermal category to reflect the amount of recoverable energy (factor of 2×10^{-2}). To calculate the amount of delivered electrical power (and energy), we assume 10 percent efficiency converting thermal energy to electricity and a power plant utilization rate of 80 percent (to infer power station electrical capacity). Table 8 shows the resulting maximum potential in the US for each type of geothermal system.

A 2012 study by the US NREL[2] estimates lower hydrothermal capacity and greater EGS capacity, but within the same order of magnitude as the INL data we use as the basis for our calculation here.

Table 8. Estimated *recoverable* US geothermal resource base to 10 km depth by type of geothermal system

Type of geothermal system	Recoverable thermal energy (EJ)	Recoverable thermal energy (GWht)	Electrical power (GWh)	Electrical capacity (GW)
Hydrothermal	50	1.38×10^7	1.38×10^6	196
Shallow EGS	875	2.28×10^8	2.42×10^7	3,450
Deep EGS	66,500	1.84×10^{10}	1.84×10^9	262,560
Current (2020) US electrical production capacity[3]				1,117

Estimated geothermal potential in Canada

Geothermal data and analysis are more limited for Canada. As in the US, the easiest-to-reach geothermal opportunities (hydrothermal and shallow-EGS) are in the western part of the country: British Columbia, Alberta, and the Yukon. The opportunities in eastern Canada almost exclusively require deep EGS. But the lack of good survey data (with a few exceptions) means it is difficult to estimate geothermal capacity in much of the country, particularly east of Saskatchewan.

A 2012 analysis by the Geological Service of Canada notes that existing datasets only cover the geothermal potential of about 40 percent of Canada's landmass, and that much of this area requires deep EGS.[4] The report does not attempt to estimate potential recoverable thermal energy.

In 2017, a research program under the auspices of the Institut de recherche d'Hydro-Québec (IREQ), supported by the National Research Council of Canada, surveyed the geothermal potential in Quebec along the north and south shores of the St. Lawrence River, east of Montreal.[5,6] This work found substantial evidence of good deep-EGS reservoirs at depths of up to 7 km but did not attempt to quantify the potential extractable energy from these reservoirs.

In 2018, a research group performed a more detailed analysis of the Western Canada Sedimentary basin in northeastern British Columbia.[7] This analysis identifies four areas favourable for geothermal reservoirs and estimates a potential total power capacity of 107 MW. The paper made no attempt to identify potential reservoir types, but the nature of the geology suggests they could be a mix of hydrothermal and shallow EGS.

Work is currently underway to determine the geothermal potential in the Garibaldi Volcanic Belt in southwestern British Columbia and will continue into 2022.[8,9] An interim report released in 2021 claims promising results but does not make detailed claims about the geothermal potential.

Notes

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Appendix 4. Canadian context: Associations, projects, companies, government agencies, and research groups

Geothermal associations and networks

Canadian Geothermal Energy Association (CanGEA)

CanGEA is a not-for-profit industry association for the Canadian geothermal industry that focuses on large-scale industrial use of geothermal energy (power generation or industry-scale use of direct heating). (https://www.cangea.ca/)

Geothermal Canada

Geothermal Canada is a not-for-profit organization committed to advancing science and promoting geothermal research and development in Canada. Funded by its members, the organization provides networking, outreach, and resource-sharing for companies and other organizations or individuals with an interest in or working on geothermal energy. (https://www.geothermalcanada.org/)

Projects: electricity generation

Estevan, SK: Deep Corp.

Deep Corp. is developing a 5 MW geothermal power generation facility. In 2020, Deep Corp. announced sufficient capacity to start with a 20MW plant, potentially scaling up to 100MW. Drilling and construction are underway. (www.deepcorp.ca)

Fort Nelson First Nation, AB: Clark Lake project

In 2021, the Federal Government committed 40.5 million CAD towards this project (total budget ~100 million CAD), which leverages roads, well pads, and some wells from the Clark Lake gas field. Depth: about 2.5 km. (https://www.canada.ca/en/natural-resources-canada/news/2021/03/canada-invests-in-cutting-edge-indigenous-geothermal-electricity-production-facility.html)

Greenview, AB: Alberta No. 1

A project led by Terrapin Geothermics expected to provide 10 MW baseload power. Construction approved in August 2019. (https://www.albertano1.ca/)

Little Salmon Carmacks First Nation, YK

In early 2020, Little Salmon Carmacks First Nation announced a partnership with Eavor Technologies to construct a generating station using the Eavor-loop technology.

(https://www.thinkgeoenergy.com/eavor-signs-partnership-agreement-for-geothermal-project-in-the-yukon-canada/)

Rocky Mountain House, AB: Eavor-lite demonstration

Launched in 2019 as a demonstration project for Eavor Technologies' closed loop geothermal heat extraction technology, and successfully completed in 2020. Independent assessment by TNO, the Dutch organization for applied research, called the demonstration a success and the company is now looking for partners with which to commercially roll out the technology. (https://www.eavor.com/eavor-lite/).

Swan Hills, AB

A project led by Razor Energy Corp. with a mix of natural gas plus geothermal heat recovery for electricity production plus carbon sequestration. Initially approved in 2011, construction commenced in spring 2021. Total anticipated power capacity of 21 MW (geothermal contributing upwards of 3 MW). (https://www.thinkgeoenergy.com/hybrid-gas-geothermal-project-to-commence-alberta-canada/)

Projects: heat only

Kitselas First Nation, BC

A collaboration launched in 2012 between Kitselas Geothermal Inc. and Borealis Geopower to construct and manage a district heating and cooling facility. (https://www.kitselasgeo.ca/)

Valemount, BC: Sustainaville Project

Borealis Geopower is developing a low temperature geothermal reservoir to provide a district heating system to serve the community of Valemount. Borealis GeoPower won exploration rights in 2010 and obtained drilling permits in 2018. (https://www.therockymountaingoat.com/2018/09/geothermal-power-update-explorers-assess-next-moves/)

Stalled or cancelled projects

Fort Liard, NWT

A proposed electricity project led by Borealis Power commenced in 2011 but stopped in 2013 when the project was unable to obtain a power purchase agreement from NTPC (Northwest Territory Power Corp.) for the supply of power to Fort Liard. (https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/current-investments/community-based-geothermal-demonstration-remote-first-nations-community/12410)

West Moberly First Nation, BC: Geothermal EcoPark

Launched in 2018, the project was stalled due to conflict with BC Hydro's "Site C" project. Legal action is ongoing (https://www.thestar.com/vancouver/2019/08/27/bc-government-first-nation-facing-lengthy-trial-over-site-c-dam.html)

Canadian geothermal development companies

Borealis GeoPower

Head office: Calgary, AB. Established in 2007, focused on developing geothermal projects. Provides consulting services as well as project development (including exploration work) and construction. https://www.borealisgeopower.com

Deep: Deep Earth Energy Production

Head office: Saskatoon, SK. A privately held corporation focused on developing Saskatchewan's geothermal power generation resources. https://deepcorp.ca/

Eavor Technologies Inc.

Head office: Calgary, AB. Developed a "closed loop" technology for EGS. Has successfully tested this technology and recently received 40 million USD funding from partners including, BP Ventures, Chevron Technology Ventures, and Temasek. https://www.eavor.com/

Razor Energy Corp.

Head office: Calgary, AB. A publicly traded "junior" oil and gas development company with a subsidiary (Futura Power) that is focused on power generation and geothermal projects. Currently involved in the South Swan Hills project, which mainly comprises natural gas power generation (21 MW) with some co-produced geothermal heat recovery energy (3 MW) and (potentially) carbon sequestration. https://www.razor-energy.com/

Terrapin Geothermics

Head office: Edmonton, AB. Develops emission-free energy projects that leverage waste heat and/or geothermal heat resources. https://www.terrapingeo.com

Government agencies

Alberta Innovates

Alberta Innovates is Alberta's research and innovation agency. It currently has a program on renewable and alternative energy and funds Eavor Technologies Inc.'s Eavor-Lite demonstration project. (https://albertainnovates.ca/impact/newsroom/supporting-innovative-geothermal-project/)

Centre Géoscientifique de Québec (CGQ)

CGQ is a partnership between the Centre Eau Terre Environnement of the INRS and the Quebec division of the Geological Survey of Canada, Natural Resources Canada. CGQ research responds to current socio-economic issues by increasing knowledge related to regional geology, georesources (groundwater, minerals, and fossil fuels), and environmental geosciences, including the impacts of climate change. (http://cgq-qgc.ca/fr/accueil)

Mitacs

Mitacs is a Canadian nonprofit research organization (funded by governments, academia, and industrial partners) that supports research and training programs to foster industrial and social innovation. Mitacs funds a small number of geothermal-related positions and projects, including one current project analyzing the challenges to geothermal projects in Alberta due to the lack of a standardized licensing and permitting process. (https://www.mitacs.ca/en/projects/regulating-geothermal-energy-alberta)

Natural Resources Canada and the Geological Survey of Canada

Natural Resources Canada manages several programs (funding, grants, incentive programs) to encourage research, development, and capability demonstration in Canada. Some funding has been directed towards geothermal projects, but NRC does not have a specific geothermal energy focus area. (https://www.nrcan.gc.ca/home)

Natural Sciences and Engineering Research Council of Canada (NSERC)

NSERC provides grant funding to university and industrial researchers across a wide range of science and engineering disciplines and topics, including some areas related to geothermal energy exploitation. (https://www.nserc-crsng.gc.ca/)

University research groups

Faculty from universities across Canada are widely engaged in scientific, engineering, social, and political issues related to the climate crisis. A small number of institutions have created special cross-disciplinary groups, institutes, and laboratories focused on renewable and geothermal energy.

Concordia University, Sustainable Energy and Infrastructure Systems Engineering (SEISE)

The SEISE focuses broadly on energy systems engineering. One project is looking at the potential for geothermal energy (availability, potential for geothermal storage, district heating) in the far north. (https://users.encs.concordia.ca/~fuzhan/SEISE%20Lab/)

Institut national de la recherche scientifique (INRS), Centre Géoscientifique de Québec, Geothermal Open Laboratory

The Geothermal Open Laboratory provides free access to technology and services for gathering and analyzing geological data, including data useful for geothermal prospecting and analysis. In exchange for this service, the institute obtains the rights to resulting data and analysis for three years, which is archived and maintained in a publicly accessible database. (https://inrs.ca/en/research/research-facilities/find-a-research-facilitie/open-geothermal-laboratory/)

University of Alberta, Faculty of Sciences, Geothermal and Alternative Energy.

An interdisciplinary Energy Systems focus area involving 200 faculty across 23 departments. In addition to performing basic research, associated faculty members are supporting Alberta- and BC-based geothermal projects. (https://www.ualberta.ca/science/geoenergy.html; https://geothermics.ca/)

University of Calgary, Geothermal Energy Laboratory

The Geothermal Energy Laboratory performs basic and applied R&D on topics related to the identification and exploitation of geothermal resources, including issues related to sustainability, policy, and law. Funding is provided by Government agencies (NSERC, Mitacs, Alberta Innovates) and industry partners. (https://www.ucalgary.ca/labs/geothermal-energy/lab)

University of Victoria, Institute for Integrated Energy Systems

Although not focused specifically on geothermal, the Institute's mandate is to chart feasible pathways to sustainable energy systems through the development of new technologies, processes, and systems. (https://www.uvic.ca/research/centres/iesvic/index.php)

University of Waterloo, Waterloo Institute for Sustainable Energy

The Institute's mission is to "conduct original research and develop innovative solutions and policies to help transform the energy system for long-term sustainability." The Geomechanics group within the Institute engages in a variety of projects related to geothermal energy, including ones on hard rock drilling, geothermal reservoir creation, and efficient low-temperature thermal power conversion. (https://wise.uwaterloo.ca/research/our_labs/geomechanics_group)

Appendix 5: Estimating Canadian and global investment in deep, hard rock drilling

We can only make a rough estimate of the annual spending on hard rock drilling R&D, given the limited public data and the proprietary nature of relevant commercial databases. However, we believe the estimates below are accurate within an order of magnitude and reflect a large blind spot around the perceived importance of cost-effective, deep, hard rock drilling.

Deep drilling R&D in Canada: ~1 million CAD/USD

Table 9 shows Statistics Canada data on R&D spending for the category "Oil and gas extraction, contract drilling, and related services."[1] Canada has generous tax credits for qualifying R&D, which means that it is likely that most drilling and oil and gas services companies report R&D activities to qualify for such tax credits.

Table 9. Canadian R&D spending: Oil and gas extraction, contract drilling, and related services

Energy Tech Category:	2014	2015	2016	2017	2018	2019	
Total Energy Technologies	1,092[B]	x	563[A]	x	486[B]	527[C]	*= Fossil fuels + others*
Fossil Fuels	1,076[E]	x	554[A]	x	486[B]	459[C]	*Fossil = sum of 4 rows below ('18/'19)*
Crude Oil & Nat Gas exploration	145[C]	x	x	99[B]	106[B]	95[B]	
Crude Oil & Nat Gas prod. & storage	195[A]	80[C]	78[B]	x	115[B]	71[C]	
Oil Sands & heavy crude surface & sub-surface prod.	x	x	x	x	258[D]	288[D]	
Refining, processing, upgrading of fossil fuels	x	x	x	x	5[B]	2[C]	
Renewable Energy Resources						0	
Nuclear Fission and Fusion						0	
Electric Power						0	
Hydrogen and Fuel Cells						0	
Energy Efficiency	x	x	x	x	0[D]	67[C]	
Other Energy related (Including carbon CCS)	0[A]	0[A]	0[A]	0[B]	..	0[B]	

x suppressed to meet the confidentiality requirements of the *Statistics Act*
F too unreliable to be published
[A] data quality: excellent
[B] data quality: very good
[C] data quality: good
[D] data quality: acceptable
[E] use with caution

Canadian firms and governments spent 527 million CAD on R&D for oil and gas extraction, contract drilling, and related services in 2019, of which 459 million CAD was spent on fossil fuels. R&D has decreased significantly since 2014 (1.1 billion CAD spent in 2014), a trend that tracks with the price of oil/gas.

How much of this 527 million CAD was spent on drilling technology? We can start by dropping irrelevant categories, such as the 67 million CAD spent on energy efficiency, leaving 459 million CAD in the four fossil fuel categories. Of these categories, we can also eliminate 71 million CAD spent on production and storage, and the 299 CAD million spent on oil sands and heavy crude, since R&D here was focused on extraction and environmental concerns (things like steam-assisted gravity drainage and extraction technologies) rather than drilling.

That leaves roughly **95 million CAD** spent on R&D in "Oil / Natural Gas Exploration." Any R&D spending on drilling technology in 2019 would be part of this 95 million CAD.

Given the large number of domains (e.g., exploration, geophysics) covered under this category and that it also encompasses oil sands research and oil/gas extraction technology, one can aggressively estimate (i.e., at the upper bound) that 10 percent of this (~10 million CAD) was spent on improvements in drilling (probably less). Next, we can aggressively estimate (i.e., at the upper bound) that perhaps 10 percent of the R&D in improvements in drilling **(~1 million CAD)** was spent on hard rock drilling (since deep/hard rock drilling is not an oil and gas priority). These assumptions yield our ~1 million CAD/USD estimate, which is likely too high.

Other Canadian data sources

Energy sector companies and industry groups are quite public about their R&D spending. For example, the Canadian Energy Centre claims major oil and gas companies spent 1.6 billion CAD on R&D to reduce their environmental footprint in 2020—up 400 million CAD from the previous year.[2] There are many articles[3] and research firm reports[4] that back these numbers.

But these data are impossible to disaggregate to determine R&D spending on deep, hard rock drilling. Given that drilling is typically not an oil and gas priority (as opposed to research on improving oil sands production and reducing greenhouse gas reductions in the production process, etc.), only a small percentage is likely spent on drilling R&D—let alone on deep, hard rock drilling.

Deep drilling R&D in the EU: ~7 million EUR

There is no single "Statistics Canada-like" data source for the EU, nor a centralized R&D funding organization. It is reasonable to expect EU R&D in deep drilling to be somewhat more than Canada but less than the US, because most of the drilling supply companies that do their own R&D are based in the US. There are a few large drilling research projects in the EU, such as the ORCHYD project (4 million EUR) and CORDIS (5 million EUR) that are funded under the EU Horizon 2020 multi-year R&D program.[5] Collectively, we estimate that approximately **5 to 7 million EUR/USD** are being spent on deep, hard rock drilling per year. Correspondence with Canadian geothermal researchers supports this estimate.

Deep drilling R&D in the US: ~10 million USD

As in the EU, the US has no centralized database tracking annual R&D spending on deep, hard rock drilling. We estimate this figure to be approximately 10 million USD based on the relative size of the US economy vis-à-vis Canada and the EU.

Start-ups and deep drilling R&D:

Small companies like Strada Global or GA Drilling may do in-house R&D, but these amounts are likely small (a few million). Plus, these companies are very secretive, so it is difficult to find information about them. It is also possible that they do most of their R&D in partnership with other companies or government research agencies, but that the amounts are too small to be easily visible in agency reporting.

Notes

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Appendix 6: Temperatures required to power hard-to-abate sectors

Industry	Sub-process with highest temperature requirements	Notes about industry/process	Temp (°C)	Source
Iron	Direct reduction of iron ore to make iron (DRI).	The DRI method produces 97% pure iron. The DR process involves heating iron in a furnace. The blast furnace process is 1,000°C max.	800 to 1,200°C	[1]
Iron (new/more efficient process)		Not yet proliferated in the industry, but moving in that direction.	1,400° to 1,500°C	[2]
Crude steel	70% made from pig iron with blast furnace technique		~1,650°C	[3]
Cement	Reaction, of the oxides in the burning zone of the rotary kiln, to form cement clinker—i.e., heating limestone, clay, and sand in kiln via fuel combustion.	The majority of cement kilns burn coal (IEA/WBCSD, 2009), but fossil or biomass wastes can also be burned.	1,510°C (some say 1,400°C)	[4]
Ammonia Production (for fertiliser)	Combining nitrogen from the air with hydrogen derived mainly from natural gas (methane) into ammonia (known as the Haber Process)		500°C	[5]
Pure aluminium (Ultrapure aluminum) 99.996%)			660.37°C	[6]
Pure aluminum (High pure aluminum (99.5%)			657°C	[6]
Pure aluminum			643°C	[6]

(pure aluminum (99.0 %)				
Aluminum Alloys (A413type has highest temperature requirements)			649 to 760°C	[7]
Paper	Highest temperature in the process of generating the steam used in paper-making; creates heat for drying paper after it has been laid.	60 °C heat source and supplying it to a 175 °C steam load at 0.8 MPa (performance taken from a SGH165 heat pump with integrated steam compressors).	175°C (steam)	[8]
Lead	Melting temperature		327°C	[9]
Copper	Roasting		600°C	[10]
Silver	Refinement (modern techniques)		962°C	[11]
Gold		Melting temperature	1,064°C	[12]

Notes

[1] McCann, G., V. Strezov, J. A. Lucas, T. Evans, and L. Strezov. (2004). "Iron Ore Characterisation during High Temperature Thermal Processing." *Dev. Chem. Eng. Mineral Process*. 12: 369-382. https://doi.org/10.1002/apj.5500120412.

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