



# Geothermal Development at Oil and Gas Scale

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A Strategic Investment Case for Oil Majors in  
Premium-Priced Baseload Power

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## Executive Summary

A structural shift in global electricity markets is creating a new, premium-priced asset class: firm, locally-produced, low emission, and baseload power contracted on long-term agreements with the world's most creditworthy counterparties. This memorandum presents the data-driven case that oil and gas majors are uniquely positioned to capture this market through scalable geothermal deployment – and that the financial returns, risk profile, and strategic fit justify material capital allocation at the scale of tens of billions of dollars per company.

The core thesis is built on four independently verifiable pillars:

**The demand is real, concentrated, and growing faster than supply.** Global data center electricity consumption is projected to roughly double from ~450 TWh in 2024 to ~945 TWh by 2030 (IEA Base Case), with a plausible range up to 1,700 TWh by 2035 in accelerated scenarios.<sup>1</sup> The United States alone requires 45–65 GW of incremental firm generation capacity by 2030, with a further 40+ GW from Europe and Asia-Pacific.<sup>2</sup> Grid interconnection queues exceeding five years in key markets mean that co-located and behind-the-meter power solutions command a structural premium. This is not speculative – data centre demand contributed an estimated \$9.3 billion to capacity market price increases in Pennsylvania/New Jersey/Maryland grid, the largest electricity grid operator in the United States, in a single year (the 2025/26 Base Residual Auction).<sup>3</sup>

**Hyperscalers are paying today for additive firm power - at prices that deliver oil-major-scale returns on geothermal investment.** While natural gas is the dominant, scalable fuel meeting today's explosive data center demand, it has established a price floor. Facing grid constraints, hyperscalers are proving they will pay a 60-100% premium over wholesale power prices for new, dedicated, always-on capacity.

In the United States—the most transparent market—power purchase agreements for firm, carbon-free baseload power are being signed at \$70–115/MWh for 15–20-year terms with investment-grade counterparties including Microsoft, Google, Meta, and Amazon. Market evidence reveals a clear two-tier structure: Meta's 20-year nuclear PPA with Constellation for existing capacity is estimated at \$70–80/MWh, while Microsoft's agreement to restart Three Mile Island commands \$98–115/MWh, reflecting the \$1.6 billion restart capital investment required to deliver reliable 24/7 generation. Amazon has secured 1,920 MW of nuclear power through 2042, and Google has contracted 115 MW of enhanced geothermal from Fervo Energy.

Internationally, firm baseload power commands significantly higher prices, reflecting energy security premiums, LNG import dependence, and structural grid constraints. Market benchmarks indicate geothermal can secure \$105–180/MWh in premium jurisdictions: Europe (\$105–160/MWh, anchored to Hinkley Point C nuclear strike prices and firmed renewables costs), Japan (\$135–155/MWh, driven by post-Fukushima energy

security premiums), Taiwan (\$120-180/MWh, supported by government feed-in tariffs for strategic baseload resources), and South Korea (\$105-125/MWh, aligned with nuclear revival benchmarks). Detailed pricing methodology and benchmarks for all jurisdictions are provided in [Appendix A](#) and summarized in [Table 2](#).

**Geothermal competes directly with upstream oil and gas for capital – and the comparison is favourable.**

While the observed nuclear market spans \$70-115/MWh (with existing capacity at the lower end), geothermal, as functionally equivalent firm baseload power with identical reliability characteristics (24/7 availability, >90% capacity factors, long asset life), is positioned to command \$100-115/MWh in the US market, and \$105-180/MWh in premium international markets—pricing that reflects new-build economics comparable to nuclear, not legacy asset pricing.

At these contracted and benchmark prices, Engineered Geothermal Systems (EGS) can deliver project-level internal rates of return of 10-18% in Phase 1 (Construction 2028-2033) at early-scale capex (\$4,000-5,000/kW), rising to 14-27% in Phase 2 (Construction 2030-2038) as costs decline to \$3,000-4,000/kW through industrial learning—with base-case US returns of 11-14% (Phase 1) and 15-21% (Phase 2), and premium market returns reaching 18% (Phase 1) and 27% (Phase 2) in Taiwan.

This memorandum presents a like-for-like analysis against the types of investment that populate a major's capital allocation queue: US shale sustaining programs, deepwater tiebacks, mature basin life extensions, and frontier exploration. At \$4,000-5,000/kW for near-term projects declining to \$3,000-4,000/kW by 2035, with managed decline rates far below those of shale or deepwater, no fuel costs, and 15-25-year contracted revenues, geothermal delivers a risk-adjusted return profile that compares favorably to all but exceptional upstream opportunities – while providing portfolio diversification that commodity-exposed assets cannot.

**Nuclear validates the market but cannot fill it. Geothermal fills the gap left by both long nuclear build-out times and the intermittency of renewables.**

The current paradigm is gas-fired baseload + intermittent renewables, but these are insufficient in speed and scale to address the demand, and hyperscalers have signed ~10+ GW of nuclear power agreements in the past 18 months. The majority of these nuclear projects involve existing reactors being re-contracted, not new builds.<sup>4</sup> Small modular reactor deployment remains 2030+ at the earliest for first units, with bulk deployment in the mid-to-late 2030s.<sup>5</sup> New conventional nuclear in

the West costs \$6,600-7,800/kW overnight; First-of-a-Kind (FOAK) SMRs are running \$5,000-10,000+/kW, with aspirational Nth-of-a-Kind (NOAK) targets of \$4,000-6,000/kW that remain unproven.<sup>6</sup>

Geothermal at scale (\$3,000-4,000/kW, a range derived from IEA's Future of Geothermal Energy report) thus has a projected cost advantage over conventional new nuclear, and is broadly comparable to optimistic SMR targets – but with a 5-10 year deployment head start, and direct leverage of the existing capabilities of the oil and gas industry.

**The time is now:** Majors should establish a dedicated geothermal power business unit to deploy ~4 GW of capacity by 2030 with an initial strategic capital commitment of \$12-25 billion, building out to 25 GW globally for a total commitment of \$75-110 billion over a decade (reflecting declining unit costs from \$5,000/kW to \$3,000/kW as learning and deployment scale).

This phased approach manages capital risk, while capturing the learning curve: Phase 1 (3-5 GW) proves commercial viability at 10-18% project IRRs with \$4,000-5,000/kW capex, while Phase 2 (20-22 GW) scales to oil-major returns of 14-27% IRRs as industrialization drives costs to \$3,000-4,000/kW.

**The phased approach of oil majors should:**

- Screen and rank a global portfolio of development corridors;
- Initiate direct commercial engagement with hyperscaler energy procurement teams;
- Establish the industrial platform for a 25 GW business generating \$20 billion in annual contracted revenue by the late-2030s – a business unit comparable in scale to your largest upstream divisions, but with superior revenue certainty and no commodity exposure.

To put the ambition in perspective: Fervo Energy, a startup, is delivering 500 MW by 2028, and long term 2 GW. An oil major, applying the same factory-drilling model that industrialized shale, should target an order of magnitude more – building the 25 GW business that the market demands and oil and gas industry capabilities uniquely enable. This is not an energy transition narrative. **It is a disciplined capital deployment into a high-margin, contracted-revenue industrial market that exists only because of the capabilities, technologies, and trained workforce that the oil and gas industry developed over a century.**

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## Chapter 1

# The Market: Why This Demand Is Different

### Scale and Urgency

The AI-driven explosion in data center power demand is creating the largest discrete electricity market opportunity in a generation. The key forecasts converge on a consistent picture:

#### Global

- **IEA (April 2025):** Global data center electricity consumption projected to double to ~945 TWh by 2030 (Base Case, 114 GW), with an accelerated scenario exceeding 1,700 TWh by 2035 (204 GW). US and China account for ~80% of growth by 2030.<sup>7</sup>
- **Gartner (November 2025):** Worldwide data center electricity consumption rising from 448 TWh in 2025 (54 GW) to 980 TWh by 2030 (118 GW). AI-optimized servers alone are growing nearly fivefold, from 93 TWh to 432 TWh.<sup>8</sup>
- **Goldman Sachs Research (February 2025):** Projects ~122 GW of global data center capacity online by end of 2030, up from ~59 GW today. North America has the most scheduled capacity coming online over the next five years.<sup>9</sup>

### United States

- **S&P Global / 451 Research (October 2025):** US data center grid-power demand at 386 TWh in 2025 (46 GW), rising to 755 TWh by 2030 (91 GW).<sup>10</sup>
- **BloombergNEF:** U.S. data center power demand could reach 106 GW in 2035<sup>11</sup>
- **Grid Strategies**<sup>11</sup> estimated that utility forecasts of 90 GW additional US load by 2030 may be overstated, with a more realistic figure closer to 65 GW.

On the supply side, both the Rhodium Group<sup>12</sup> and Project InnerSpace<sup>13</sup> have identified next generation geothermal as a leading candidate to meet this demand economically: if the growth patterns of data centers follow historical clustering trends, geothermal could economically meet up to 64% of expected demand growth by the early 2030s under baseline assumptions.

**Table 1 : Forecasts for Growth in Power Demand for Data Centers**

Forecaster	Year	Installed Power	5-year Growth	Comments
Global		GW	GW	
IEA (Global Data Centers)	2025	57	57	US & China account for 80% of growth to 2030
	2030	114		
	2035	204	91	2030-35: Growth accelerates
Gartner (Global data Centers)	2025	54	64	AI accounts for 39 GW of 5-year growth to 2030
	2030	118		
GS (Global Data centers)	2025	59	63	North America is the majority of growth
	2030	122		
S&P (Global Data Centers on Grid)	2025	103	87	
	2030	191		
USA				
S&P (US Data Centers on Grid)	2025	46	44	
	2030	91		
Utility aggregate 5-year growth forecasts submitted to FERC for Data Centers	2025	Not Supplied	90	Total national peak load growth: 166 GW of which Data Centers 55%.
	2030			
Grid Strategies (US Data centers)	2025	Not Supplied	65	"Utility aggregate forecasts may be overstated"
	2030			
BloombergNEF (US Data Centers)	2025	40	10-year growth	Increased its forecast from 78 GW eight months earlier.
	2035	106	66	

**Note: Conversions of TWh ↔ GW assume ~95% average load factor for data-center electricity demand**

Table 1 summarizes 5-year growth forecasts. There is legitimate debate about whether all announced data center capacity will materialize. S&P Global is an outlier in 2025 – perhaps its definitions are wider. For capital allocation purposes, we use a conservative range of 45–65 GW of incremental firm capacity (including reliability margin) required in the US between 2025 and 2030. Even at the lower bound, this is an unprecedented market. Further, the IEA has forecast an acceleration in global demand between 2030 and 2035.

## The Grid Cannot Deliver – Creating the Premium

Grid expansion cannot accommodate the exploding load growth associated with data centers. Interconnection queues in Pennsylvania/New Jersey/Maryland (PJM), Texas (ERCOT), and European markets exceed five years. Data center demand in PJM alone contributed \$9.3 billion to capacity market price increases for 2025–26 “BRA”, pushing monthly residential bills up ~\$17 pcm (10–15%) in Ohio and Maryland.<sup>14</sup> Facing this constrained and expensive grid, hyperscalers are increasingly taking control of their power supply, including through co-location. While they are making landmark investments in future nuclear capacity, the immediate, scalable solution powering load growth is overwhelmingly natural gas.

**Gas-Fired Growth is the Baseline:** Over 80% of the power capacity currently under development to directly serve data centers in the U.S. is natural gas-fired generation<sup>15</sup>. This is the de facto standard for new, firm, dispatchable power today. By contrast globally, gas and coal together are projected to meet more than 40% of data centre electricity demand until at least 2030, with coal playing a significant role across much of Asia, where it still dominates national grids and, by extension, the power consumed by data centres built on them<sup>16</sup>.

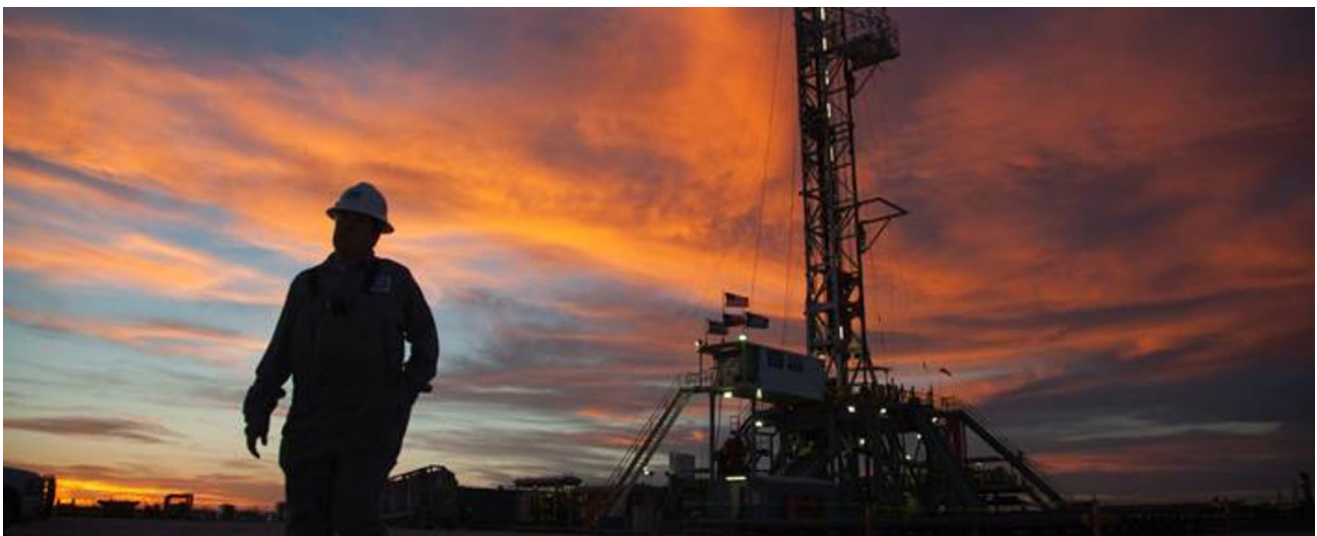
**Nuclear Defines the Premium:** Simultaneously, these same buyers are paying a historic premium to secure additional firm capacity:

- Microsoft signed a 20-year PPA with Constellation to restart 835 MW Three Mile Island nuclear plant.<sup>17</sup>
- Amazon expanded its Talen Energy PPA to 1,920 MW of nuclear power through 2042.<sup>18</sup>

- Meta signed a 20-year PPA with Constellation for 1,121 MW from Clinton nuclear plant and secured up to 6.6 GW of nuclear power across multiple deals.<sup>19,20</sup>
- Google secured 115 MW of geothermal from Fervo Energy via a clean transition tariff in Nevada and 500 MW of SMR power from Kairos by 2035.<sup>21</sup>

Analyst commentary tied to recent data-center nuclear offtake agreements indicates that hyperscalers are willing to pay meaningful premiums for firm nuclear capacity, with pricing for specific deals falling into a discernible range even where contract details remain undisclosed. Jefferies estimated that Meta’s 20-year PPA with Constellation Energy for the Clinton Clean Energy Center is priced at approximately \$70–\$80 per MWh, which reflects a premium compared with regional wholesale power and wind PPA costs.<sup>22,23</sup>

In contrast, multiple analysts estimate Microsoft’s 20-year agreement with Constellation to restart the Three Mile Island Unit 1 nuclear plant carries an implied price in the range of \$98 per MWh, with Jefferies specifically estimating \$110–\$115 per MWh and Morgan Stanley estimating \$98 per MWh.<sup>24,25,26</sup> The higher pricing for the Microsoft deal is driven in part by the \$1.6 billion capital investment required to restart the shuttered facility and deliver reliable 24/7 generation.<sup>27</sup> This is not a marginal green premium. It is a bid for energy security from counterparties with investment-grade credit and \$100+ billion annual capital budgets. Natural gas is meeting the urgent volume demand, while nuclear contracts reveal the high price these buyers will pay for additional capacity. Appendix A reviews the market prices for other jurisdictions and Table 2 summarizes. These prices are used to calculate investment returns across the world, reported in Appendix B.



**Table 2 : Firm Power Price Ranges by Jurisdiction (2026)**

Jurisdiction	Price (\$/MWh)	Market Benchmark	Key Driver
<b>USA</b>	\$100-115	Microsoft-Constellation Three Mile Island Nuclear PPA (\$98-\$115/MWh); Meta-Constellation Clinton Nuclear PPA (\$70-\$80/MWh)	Scarcity value of firm, dispatchable, zero-carbon baseload. Hyperscale buyers paying ~2x wind/solar PPAs (\$50-60/MWh) for 24/7 CFE matching, grid independence, and elimination of balancing risk.
<b>Europe / UK</b>	\$105-160	Hinkley Point C Inflation-Adjusted Strike and Firmed Renewables Portfolio Cost (\$145-150/MWh)	Cost of reliability and 24/7 availability. High carbon prices, grid congestion, and balancing costs to firm intermittent renewables for industrial baseload.
<b>Japan</b>	\$135-155 {FIT: \$170-\$180/MWh}	New Nuclear LCOE (\$120-\$150/MWh) plus Historical Non-Fossil Feed-In-Tariffs (FiT); Highest OECD Industrial Power Tariffs	Extreme import dependence (LNG). Energy security premium for domestic, fuel-free firm generation post-Fukushima. Geothermal as nuclear substitute in constrained, high-price market.
<b>Taiwan</b>	PPA: \$120-180 FIT: \$156-280	MOEA Geothermal FiTs: \$156-\$188/MWh (conventional), up to \$280/MWh (next-gen systems); Bilateral PPA modeling for firm baseload	Nuclear phase-out + LNG import dependence. Geothermal positioned as critical national infrastructure and nuclear substitute. Energy security, grid independence, and insulation from fuel price volatility for hyperscale data centers.
<b>South Korea</b>	\$105-125	KEPCO Industrial Tariff Adjustments. Nuclear Reactor Revival Plans.	Grid reliability mandates firm capacity. Nuclear revival sets implicit benchmark for firm, low-carbon power value. Data centers facing materially higher costs with differentiated peak pricing—geothermal provides 24/7 hedge against tariff volatility and balancing risk.



## AI Dynamics: Why Geothermal Is Expanding the Market Rather Than Competing Within It

The demand growth picture is incomplete without understanding what sits upstream of data center operators – hugely profitable and expanding GPU manufacturing capacity. Every terawatt-hour of firm power that comes online is a terawatt-hour of AI compute driving GPU manufacturers' revenues (estimated at \$20 billion for a GW of AI Capacity, based on power consumption of 1.4W per H100 GPU including infrastructure). Power is not a cost center for GPU manufacturers – it is the binding constraint on their total addressable market. This reframes the entire competitive dynamic for geothermal.

GPU Manufacturers and hyperscalers alike are (at least, privately) indifferent to whether data centers are powered by geothermal, gas, nuclear, or even coal. According to IEA, coal produced 35% of global electricity in 2024, an all-time high. What drives their profits is terawatts of reliable power, deployed as fast as possible, wherever it can be delivered. Current and announced chip delivery contracts imply tens of GW of incremental data center power demand through the end of the decade – demand that must be met by someone, with something, somewhere.

If even a fraction of GPU manufacturers' implied demand signal translates into contracted power procurement – and the hyperscaler capex commitments of \$200+ billion annually suggest it will – then the geothermal industry is looking not at a niche opportunity but at a market that could absorb tens of GW of new geothermal capacity on top of every gigawatt of gas and nuclear that can be delivered. The constraint is not demand. The constraint is how fast firm power can be built.

This is the game-changer for the geothermal industry. If GPU manufacturing roadmaps proceed as planned, their demand signal alone – transmitted through hyperscaler procurement – would be sufficient to justify the industrialization of geothermal at a scale that no combination of climate policy, utility procurement, or grid modernization could achieve. GPU chip sales create a self-reinforcing cycle: more chips sold → more data centers built → more power demanded → more geothermal deployed → more data centers enabled → more chips sold. Geothermal is not competing for a fixed pool of demand. It is unlocking demand that cannot be served any other way within the required timeframe.

## For oil majors, the strategic implication is decisive:

- Geothermal does not compete with natural gas, coal or nuclear for the data center market. It expands the total market by adding capacity that gas and nuclear power cannot deliver on the required timeline. Every GW of geothermal that comes online enables another GW of AI compute – and another revenue stream for chip makers, cloud providers, and power suppliers alike.
- The addressable market for geothermal is not the residual left after gas, coal and nuclear. It is additive to both. This is a positive-sum market, not a zero-sum one.
- An oil major deploying 25 GW of geothermal by the late-2030s is not cannibalizing its gas business. It is building a parallel, contracted-revenue business on top of it – serving demand that would otherwise go unmet, leaving AI compute stranded and AI chips unsold.

If the GPU manufacturing trajectory holds, geothermal's market opportunity is measured not in single-digit GW but in the tens to hundreds of GW globally. The only question is whether the supply side – led by companies with the capability and capacity to deliver – will scale fast enough to capture it.

## The Global Opportunity – Not Just a US Story

The five largest data center markets today are the US, China, Europe, and emerging hubs in Southeast Asia and the Middle East. [See Table 3](#). Each presents distinct geothermal opportunities: Europe and Asia deserve particular attention. European wholesale electricity prices are structurally 50–100% higher than US prices, meaning geothermal's current LCOE (\$60–90/MWh) is already competitive without requiring a "reliability premium."

Indonesia alone has more untapped geothermal potential than the entire current global installed base. These are markets where oil majors already operate and possess subsurface data, regulatory relationships, and supply chain infrastructure.

## The Size of the Prize: Total Achievable Potential by Continent (GeoMap)

The scale of global geothermal resources is not a constraint on the investment thesis – it is the foundation of it. Project Innerspace’s GeoMap<sup>32</sup>, the most comprehensive global geothermal prospecting database currently available, models technically achievable electricity generation potential using a HIP (Heat in Place) Volumetric Model. HIP is translated into electricity generation with a probabilistic approach (Montecarlo) that yields a distribution of outcomes, using P50 as reference numbers.

The results are striking in their magnitude and in how unevenly the opportunity is distributed across geographies – a direct read-out for portfolio prioritization by continent.

The total near-term technically recoverable geothermal electricity potential across all continents at depths <5km is ~49,300 GW, with long-run potential as next generation geothermal technologies mature around 370,400 GW, to produce geothermal energy at depths 5-7 km – roughly 40 times current global total electricity generating capacity.

Table 4 and Appendix C summarize the GeoMap data by continent, cross-referenced to current installed geothermal capacity.

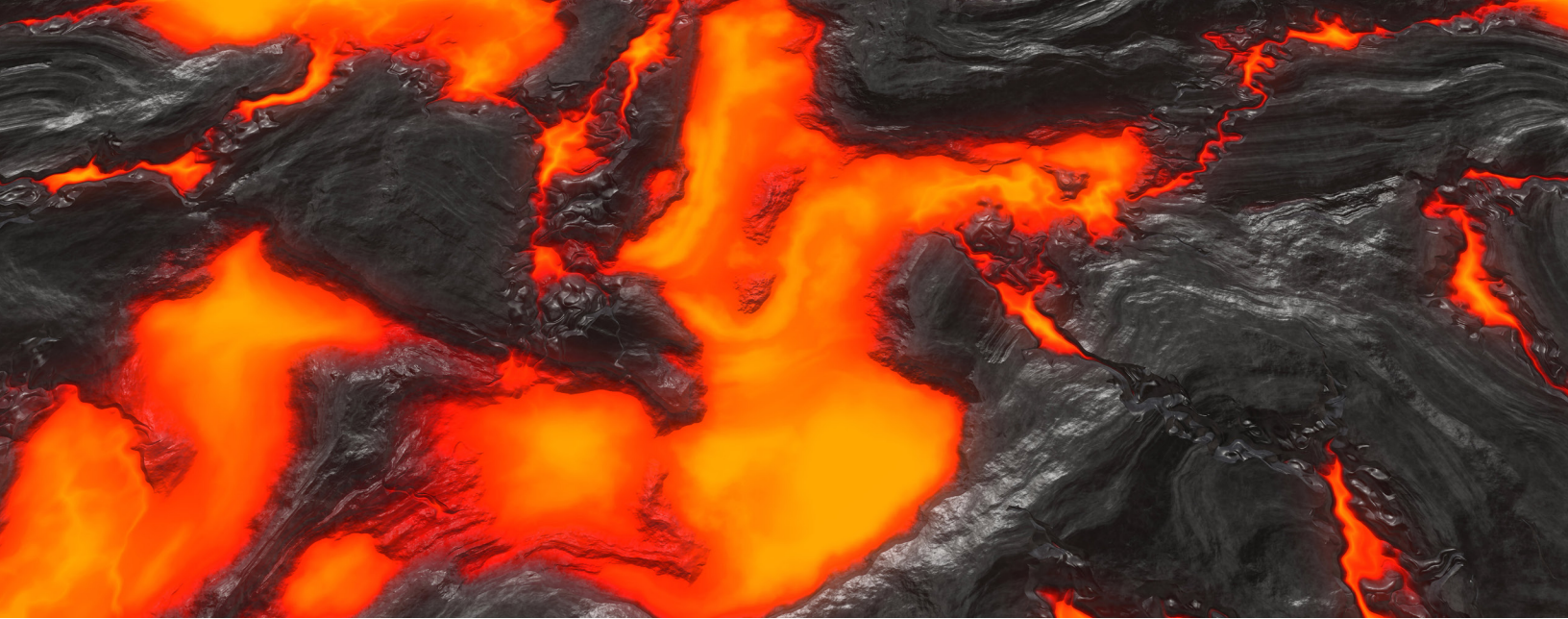
**The gap between current deployment (~17 GW globally) and near-term potential (~49,300 GW) represents one of the largest untapped industrial opportunities in the energy system.**

**Table 3 : Regional Forecasts of Data Center Energy Consumption**

Region	Demand (2025, TWh)	Demand (2030, TWh)	Geothermal Opportunity
<b>United States</b>	~386	~755	EGS across western states; conventional in California/Nevada. EGS could meet 64–100% of US DC demand growth. <sup>12</sup>
<b>Europe</b>	~145	~238	Structurally higher electricity prices (\$80–120+/MWh). Pannonian Basin (Hungary), Upper Rhine Graben (Germany/France), Iceland, Italy, UK deep geothermal. Grid constraints acute in Dublin, Frankfurt, Amsterdam. <sup>28</sup>
<b>Asia-Pacific</b>	~267	~493	Indonesia: 24 GW geothermal potential, ~2.4 GW developed. Philippines: ~2 GW installed. Japan: high prices, loosening regulatory constraints. Singapore/Malaysia: fastest DC growth globally. <sup>29</sup>
<b>East Africa</b>	Emerging	Emerging	Kenya: 985 MW installed, ~10 GW potential. Microsoft/G42 announced \$1B geothermal-powered 1 GW DC campus. Grid is 90% renewable (50% geothermal). <sup>30,31</sup>
<b>Total</b>	~860	~1587	Including other jurisdictions.

**Table 4 : Global Geothermal Electricity Potential by Continent<sup>37</sup>**

Continent	Near-Term Elec. Potential (GW)	Long-Run Elec. Potential (GW)	Current Geo. Capacity (GW)	Key Jurisdictions & Notes
<b>Africa</b>	15,904	124,744	~1.0	Kenya (KenGen ~985 MW installed, ~10 GW potential), Ethiopia, Tanzania, Rwanda; East African Rift System as dominant resource corridor
<b>North America</b>	10,827	63,752	~5.7	USA: Western states (Nevada, Utah, California), Texas ERCOT; Canada: BC; Mexico and Central America (El Salvador, Nicaragua, Costa Rica, Guatemala, Honduras)
<b>Asia</b>	11,351	78,631	~5.4	Indonesia (24 GW potential, ~2.74 GW developed), Philippines (~2 GW), Japan (0.6), China (0.04); Ring of Fire dominates near-term opportunity
<b>Middle East</b>	4,227	28,587	~1.8	Turkey ~ 1.8; Saudi Arabia, UAE, Oman, Yemen; deep EGS potential in emerging DC hub markets; currently undeveloped
<b>Europe</b>	2,779	28,758	~1.9	Iceland, Italy, Hungary (Pannonian Basin), Germany/France (Upper Rhine Graben); structurally premium power prices
<b>South America</b>	2,589	30,123	~0	Chile, Peru, Colombia; Andean geothermal arc; substantial undeveloped high-temperature resource
<b>Oceania</b>	1,645	15,778	~1.3	New Zealand (~1.26 GW installed, hydrothermal), Papua New Guinea (0.07), Vanuatu, Fiji
<b>Global Total</b>	49,322	370,375	~17.2	Source: Project InnerSpace GeoMap, InnerSpace HIP Volumetric Model (February 2026). Near-term = Monte Carlo P50 deterministic estimate; Long-run = future next generation potential.



## Chapter 2

# Geothermal in the Capital Allocation Queue

### Revenue Equivalence

The revenue comparison between geothermal and hydrocarbon opportunities is straightforward and robust:

- 1.1 GW geothermal at 95% capacity factor × 8,760 hours × \$100/MWh = ~\$915M annual gross revenue
- 50,000 bbl/d of oil at \$50/bbl × 365 days = \$913M annual gross revenue

Therefore, ~25 GW of geothermal ≈ ~1.1 million bbl/d of oil in gross revenue – representing ~28% production-equivalent growth for a major producing ~4 MMbbl/d. This would constitute a highly material new revenue stream but with contracted prices, no commodity exposure, no dependence on hydrocarbon-producing regions or international supply chains, and no fuel cost.

**To frame it in current market context: \$20B in annual contracted revenue from a single business segment, with 15–25-year visibility and no commodity price exposure, would command a substantial premium to the market valuations currently assigned to upstream production of equivalent gross revenue.**

### Capital Intensity – A Rigorous Like-for-Like Comparison

Geothermal must compete for the same capital as upstream projects. The comparison must therefore be made against the types of investment that actually populate the capital allocation queue of a non-OPEC major – not against exceptional one-off discoveries.

### Geothermal at Scale (25 GW-mid-case target)

Estimated capex: \$75–115 billion over 10 years, with learning curve progression:

- FOAK costs (2025–2028): \$6,000–8,000/kW
- 2028–2033 (first 4 GW): ~\$4,000–5,000/kW average
- 2030–2038 (21 GW): ~\$3,000–4,000/kW average

This 40–50% cost reduction trajectory aligns with solar PV (90% reduction 2010–2023) and shale industrialization (50–60% reduction 2010–2025).

- **Sustaining Capex:** ~1%-2% of initial capex annually. EGS reservoirs experience power decline as heat is extracted from the stimulated rock volume (typically 1-3% per year<sup>33 34</sup> in output, depending on reservoir design and recharge). To mitigate this requires periodic well deepening, re-stimulation, and infill drilling – activities that are routine extensions of drilling competencies. Sustaining capex is a fraction of shale’s reinvestment burden but is not negligible. Total annual operating costs (O&M plus annualized sustaining capex for periodic well workover, re-stimulation, and infill drilling) are approximately 3-5% of initial CAPEX annually.
- **Revenue:** Contracted for 15-25+ years with investment-grade counterparties; near-zero commodity exposure. No fuel cost.
- **Decline Profile:** Managed, not zero. With active reservoir management, output can be sustained at 80-90% of nameplate over 30-40-year project lives. This compares to 35-40% first-year decline in shale and 5-10% annual decline in deepwater post-plateau.
- **Asset Life:** 20-30+ years without major intervention, and 30-50 years with sustaining capex / active reservoir management program.

### Learning Curve Economics: The Path to \$3,000/kW

Geothermal’s projected 40-50% cost reduction from FOAK to mature scale follows established precedents:

#### Cost trajectory roadmap:

- **2025-2026 (FOAK):** \$6,000-8,000/kW – Early commercial projects

- **2028-2033 (Early scale, ~4 GW):** \$4,000-5,000/kW – Pad drilling standardization, early supply chain development
- **2030-2038 (Mature scale, ~21 GW):** \$3,000-4,000/kW – Factory drilling, modular surface plants, volume procurement

This trajectory is broadly consistent with the IEA’s projected LCOE<sup>35</sup> for next-generation geothermal of approximately \$50/MWh by 2035 in its low-cost case, implying a capex of approximately \$4,000-4,300/kW – overlapping with the upper end of this roadmap’s mature-scale range.

### US Shale – Permian Basin (Sustaining 500k bbl/d plateau over 10 years)

- Total 10-year capital: \$35-45 billion (Rystad Energy, Enverus estimates)
- The decline problem is acute: first-year decline rates of ~35-40% require drilling ~200k bbl/d of new production annually just to maintain plateau
- Full-cycle breakeven: \$45-65/bbl depending on sub-basin and acreage quality
- Revenue: 100% commodity-exposed – subject to oil/gas price volatility and basis differentials
- Workforce: Continuous, high-intensity drilling activity required indefinitely

### Canadian Oil Sands / Heavy Oil (New SAGD or Expansion)

- Capital intensity: \$60,000-90,000 per flowing barrel for new projects
- Breakeven: \$55-75/bbl WCS-adjusted
- Carbon intensity: Among the highest in the global portfolio
- Long asset life but high OPEX and increasing regulatory/carbon cost exposure

**Table 5 : Impact Of Learning Curves In Cost Reduction**

Technology	Cost Reduction	Timeframe	Deployment Volume since 2010
Solar PV	90% <sup>36</sup>	2010-2023	2160 GW globally <sup>37</sup>
Onshore Wind	70% <sup>38</sup>	2010-2024	1100 GW globally
US Shale	50-60% <sup>39</sup>	2010-2025	13M bbl/d <sup>40</sup>
Geothermal EGS	45-55%	2026-2035	25 GW (per major)

## Deepwater – West Africa / Brazil Pre-Salt (New Development, ~250k bbl/d)

- Initial FID capex: \$10–18 billion (FPSO, subsea infrastructure, wells)
- Development timeline: 5–8 years from FID to first oil
- Post-plateau decline: 5–10% annually, requiring follow-on drilling (\$1–2B/y) to sustain
- Total 10-year capital to sustain ~250k bbl/d: \$20–35 billion
- Revenue: Commodity-exposed, premium crude quality provides some buffer
- Significant exploration and reservoir risk
- Political / fiscal risk in many jurisdictions

## Mature North Sea / Norwegian Continental Shelf (Life Extension)

- Sustaining capex: \$20–35/bbl for mature production
- Decommissioning liabilities: \$50+ billion across UKCS, growing annually
- UK fiscal regime: Energy Profits Levy creates uncertainty; Norwegian carbon dioxide tax rising
- Decline: Structural; most fields past peak
- Revenue: Commodity-exposed, with significant fiscal take



## Comparative Project Investment Returns

[Table 6](#) summarizes the economic results presented in [Appendix B](#) and [Table 7](#) compares typical project characteristics for geothermal projects with those for some oil and gas categories around the world.

### The Critical Insight:

Geothermal's Phase 1 IRRs of 10-18% reflect early-stage deployment with capital intensity similar to FOAK SMR projects (\$4,000-5,000/kW). However, the industrial learning curve—proven in solar PV (90% reduction 2010-2023) and shale (50-60% reduction 2010-2020)—drives Phase 2 returns to 15-21% in the USA with Investment tax credits (ITC), and up to 27% in premium markets like Taiwan. These Phase 2 returns, with >25 years of contracted, non-declining, non-commodity-exposed revenue, represent a fundamentally superior financial asset class than equivalent-revenue upstream opportunities.

## Sensitivity: What If PPA Prices Fall?

A legitimate concern is whether the current \$100-115/MWh US premium market (and \$105-180/MWh internationally) is sustainable. Our analysis suggests structural support for >>\$80 pricing through at least the early 2030s, based on:

- Grid constraint duration (interconnection queues are 5+ years and growing)
- Hyperscaler 24/7 carbon-free energy commitments (Microsoft: 2030; Google: 2030)
- Limited alternative supply of firm, low emission power before SMR maturity

However, even at a conservative \$80/MWh PPA a mature Phase 2 EGS project in the US (2035 costs of \$3,000-4,000/kW, 95% CF) delivers a project IRR of 11-13%—comparable to utility-scale infrastructure returns and still competitive with mature-basin upstream investments. This represents the downside case for Phase 2. The downside case for upstream oil at \$40/bbl is value destruction.

**Table 6 : Geothermal Project IRR Summary by Phase and Jurisdiction. Phase 1 (2028-2033) with Capex: \$4,000-5,000/kW. Phase 2 (2030-2038) with Capex: \$3,000-4,000/kW**

Jurisdiction	Phase 1 IRR	Phase 2 IRR	PPA Price (\$/MWh)	Key Drivers
USA	11-14%	15-21%	\$100-115	30% ITC; hyperscaler demand; grid constraints
Europe/UK	10-16%	14-24%	\$105-160	High carbon prices; firming renewables cost; nuclear benchmarks
Japan	12-16%	17-23%	\$135-155	LNG import dependence
Taiwan	12-18%	16-27%	\$120-180	Nuclear phase-out; strategic infrastructure status
South Korea	10-14%	14-20%	\$105-125	Nuclear revival; tariff volatility hedge

Sources: Project InnerSpace "Core to Code" analysis; Rystad Energy; Enverus; public company filings.

**Table 7 : Characteristics of Geothermal and Hydrocarbon Projects**

Metric	Geothermal (at scale, \$110/MWh PPA)	Permian Shale	Deepwater (non-advanced)	Mature North Sea
<b>Project IRR</b>	See Table 6	15-30%	12-20%	8-15%
<b>Revenue certainty</b>	15-25+ year PPA, contracted	Spot/forward commodity	Spot/forward commodity	Spot/forward commodity
<b>Production decline</b>	~1-3%/yr power decline: mitigated by well deepening and restimulation	35-40% first-year	5-10% annual post-plateau	Structural decline
<b>O&amp;M plus Sustaining capex</b>	3.5% of initial capex/year (well work, infill drilling)	\$3.5-4.5B/year for 500k bbl/d	\$1-2B/year	Rising as fields age
<b>Fuel cost</b>	Zero	Zero (but decline drilling is the "fuel")	Zero	Zero
<b>Commodity exposure</b>	None	Full	Full	Full
<b>Carbon intensity</b>	Near-zero	Moderate	Low-moderate	Moderate
<b>Counterparty credit</b>	Investment-grade (MSFT, GOOG, META, AMZN)	Market price	Market price	Market price

Post-tax, unlevered, inflation-indexed. Ranges reflect low/mid/high PPA scenarios within each jurisdiction's pricing band. Phase 1 range: 10%-18%; Phase 2 range: 14%-27%.





## Chapter 3

# The Competitive Landscape: Nuclear and Geothermal

### Existing Nuclear: Being Contracted, Not Being Built

The hyperscaler nuclear deal wave of 2024–2025 is impressive in headline terms but consists overwhelmingly of existing plants being re-contracted at premium prices:<sup>41,42,43</sup>

- Microsoft/Constellation: TMI Unit 1 restart (835 MW) – targeting 2028
- Amazon/Talen Energy: Susquehanna expansion (1,920 MW) – through 2042
- Meta/Constellation: Clinton (1,121 MW) – 20-year PPA
- Meta/Vistra: David-Besse, Perry, Beaver Valley (2,609 MW) – existing plants
- Google/NextEra: Duane Arnold (615 MW) – existing plant restart

This confirms the thesis: hyperscalers will pay substantial premiums for firm, low emission power. But the supply of existing nuclear plants available for re-contracting is finite and will be substantially exhausted within 2–3 years. The question is what comes next.

### Small Modular Reactors: Promising But Distant

SMR timelines remain aspirational.<sup>44</sup> Nuclear capex is high, but the gap with geothermal is narrower than sometimes claimed. New conventional nuclear power in the West runs \$6,600–7,800/kW overnight.<sup>45</sup> FOAK SMR costs are running \$5,000–10,000+/kW in practice, with aspirational NOAK targets of \$4,000–6,000/kW.<sup>46</sup> Geothermal at scale (\$3,000–4,000/kW) has a meaningful but not overwhelming cost advantage versus conventional new nuclear. The geothermal advantage is decisive in deployment speed and capability fit, not just capital cost.

- Only one SMR design (NuScale) has full NRC design certification—the original 50 MWe design (2020/2023). The updated 77 MWe design received a Standard Design Approval (SDA) in May 2025, a precursor to, but not equivalent to, full design certification.
- Google/Kairos: FOAK targeted 2030+. Fleet deal for 500 MW (2035).
- Meta/TerraPower: First 345 MW Sodium unit targeted “as early as 2032.”
- Amazon/X-energy: Dow’s Texas site will not receive FID until ~2028.
- Meta/Oklo: First Aurora Powerhouse (~75 MW) targeted “as early as 2030.” Previously rejected by NRC; reapplying.

## Geothermal's Positioning

Nuclear and geothermal are not zero-sum. Hyperscaler procurement teams are building diversified portfolios of firm, low emission power. Geothermal fills the deployment window between now and SMR maturity – and may prove permanently more cost-effective. The hyperscaler-driven demand signal means that the total market for firm power will expand to absorb both geothermal and nuclear at scale. The pivotal issue is whether oil and gas entities secure a position in this supply chain, or cede the entire market, which without oil and gas engagement at scale will proceed at a snail's pace, to startups and utilities.

**Table 8 : Comparison Of Geothermal And Nuclear SMRs**

Attribute	Geothermal (EGS)	Small Modular Reactor
1 <sup>st</sup> commercial delivery	2026	2030-2032 (optimistic FOAK)
2026 installed cost	\$6,000-8,000/kW (FOAK) <sup>5</sup>	\$5,000-10,000+/kW (FOAK); \$6,600-7,800/kW (conventional new)
Projected cost at scale	\$4,000-5,000/kW (2030) \$3,000-4,000/kW (2035)	\$4,000-6,000/kW (SMR, NOAK); > \$6,000/kW for conventional nuclear
Regulatory timeline	Established (drilling permits)	5-10-year NRC process
Public acceptance	Low-moderate risk	Moderate-high risk
Oil capability transfer	Direct (drilling, completions, subsurface)	Minimal
Time (FID to power)	3-5 years	7-12+ years





## Chapter 4

# The Oil Major Advantage: Why Oil and Gas Wins This Market

### The Origin of the Vision: Oil and Gas as Leaders of the Future of Geothermal

Any serious examination of the oil and gas industry's strategic case for geothermal must acknowledge the intellectual origin of that case: "[The Future of Geothermal in Texas: The Coming Century of Growth & Prosperity in the Lone Star State.](#)"<sup>47</sup> Published in January 2023 involving researchers from five Texas universities, Project InnerSpace, industry SMEs, the IEA and University Lands, this fifteen-chapter study was the first rigorous, multi-disciplinary assessment to place the oil and gas industry at the center of the geothermal opportunity.

The report featured several arguments for oil and gas leadership in geothermal that, while trailblazing and even controversial at the time, have become obvious and widely accepted - most recently punctuated by the US Department of Energy's move to reorganize geothermal into the hydrocarbons office, to create the "Office of Hydrocarbon and Geothermal Energy."

But perhaps the report's most significant contribution was its framing of the technology transfer thesis: that the oil and gas industry's accumulated capabilities in horizontal drilling, hydraulic fracturing, managed pressure drilling, and subsurface data interpretation, developed and perfected over the shale boom of the 2000s and 2010s, were directly and immediately

applicable to next-generation geothermal at commercial scale. Critically, the study argued that prior geothermal projections had systematically underestimated future growth by failing to account for the transformative impact of oil and gas industry engagement.

[Appendix D](#) summarizes key findings relevant to the oil and gas Investment case.

### The Technology Transfer Is Proven

Oil and gas industry engagement has advanced since the 2023 landmark study, and the prospect is no longer a theoretical proposition. Engineered geothermal systems require exactly the subsurface capabilities that define the core business of oil and gas majors:

- Directional drilling and completions: EGS uses horizontal wells and multi-stage stimulation, techniques perfected in shale development;
- Subsurface characterization: Geophysical interpretation, reservoir modelling, and temperature gradient analysis are direct analogues to hydrocarbon exploration;
- Pad drilling and factory execution: The "manufacturing model" that drove shale economics applies directly to geothermal well programs;
- Fluid management and reservoir engineering: Injection/production management parallels waterflooding and enhanced oil recovery;
- HSE and project execution: Multi-well pad

development under demanding safety regimes is your daily operating environment;

- Surface facilities: The absence of hydrocarbons reduces the complexity and hence cost and footprint of surface process and utilities plant. Steam and Organic Rankine Cycle power generation technologies are increasingly modular (e.g., ORC 60 MWe modules from Baker Hughes and Turboden).<sup>48,49</sup>

### **The evidence is now commercial, not merely conceptual:**

- Utah FORGE (DOE): Drilling time reduced from 310 hours (2020) to 110 hours (2023) – a 65% reduction using oilfield techniques<sup>50</sup>.
- Fervo Energy – backed by Devon Energy and Google – has reduced drilling times at its 500 MW Cape Station project to mid-teens days per well, down from ~30 days initially. Cape Station is fully contracted (320 MW to Southern California Edison, 31 MW to Shell Energy, plus Google, Clean Power Alliance, and others). Approximately 100 MW of operating capacity by early 2027; full 500 MW by 2028<sup>51,52</sup>.
- In March 2026, Fervo closed \$421 million in oversubscribed non-recourse project financing for Phase 1 of Cape Station – the first non-recourse debt financing ever achieved for a commercial-scale EGS project. The facility comprised a \$309 million construction-to-term loan, a \$61 million tax credit bridge loan, and a \$51 million letter of credit, syndicated across nine institutional lenders, including RBS, Barclays, BBVA, HSBC, MUFG, Société Générale, J.P. Morgan, Bank of America, and Sumitomo Mitsui Trust Bank. As Fervo's CFO stated: 'Non-recourse financing has historically been considered out of reach for first-of-a-kind projects. Cape Station disrupts that narrative.'<sup>53</sup>

- Devon Energy has embedded subject matter experts with Fervo's drilling teams – the first systematic oil major technology transfer to EGS<sup>54</sup>.
- SAGE's first deployment in a Texas county is a 3-MW Geopressured Geothermal System developed under a land use agreement with San Miguel Electric Cooperative to supply dispatchable geothermal power and energy storage into the ERCOT grid<sup>55</sup>.
- XGS signed a PPA for 150 MW and has demonstrated technology viability in Coso field<sup>56</sup>.
- Shell Energy signed a 15-year PPA with Fervo – the first oil-adjacent entity to purchase EGS power commercially<sup>57</sup>.

### **Translating Oil and Gas Expertise into Geothermal Development:**

Building on the strategic vision established by earlier studies, the practical pathway for scaling geothermal through oil and gas capabilities has been mapped in granular detail. This work was conducted under the U.S. Department of Energy's [Geothermal Energy from Oil and Gas Demonstrated Engineering \(GEODE\)](#) program<sup>58</sup>. Project InnerSpace serves as the Prime administrator, in partnership with the Society of Petroleum Engineers (SPE) as a partner administrator of the program. The GEODE initiative, in collaboration with more than 130 member entities, many of them oil and gas entities, has produced a comprehensive set of roadmaps focused on technology, skills, and methodologies transfer into geothermal. These roadmaps cumulatively total 1,000 pages of consensus reached after more than a year of work, amongst the oil and gas industry, big tech, utilities, banks, and researchers. These roadmaps, completed in 2025, have not yet been published by the U.S Department of Energy's Geothermal Office ([Appendix E](#)).



## Geothermal Finance at Oil and Gas Scale

Project InnerSpace recently published “[Minding the Gap: Geothermal Financing at Oil and Gas Scale](#),”<sup>59</sup> after a three year analysis to identify and resolve the structural barriers preventing large-scale capital flow into the geothermal sector. This analysis, which incorporated insights from over 100 subject-matter experts across the investment, insurance, and O&G sectors, and identified the key actions that could unlock the flow of capital into geothermal.

Key findings indicate that the financial standards and instruments utilized by the oil and gas sector that have supported the flow of trillions into oil and gas development are uniquely positioned to address the most critical “valleys of death” in scaling geothermal, including:

- **Technical Performance Immaturity:** Bridging the gap between pilot-scale technology and industrial-scale reliability;
- **Commercialization and Market Capacity:** Utilizing major-scale balance sheets to underwrite the transition from project-by-project funding to portfolio-scale deployment;
- **Regulatory and Information Gaps:** Adapting proven oil and gas best practices for subsurface data management and risk-based safety standards to the geothermal context.

## What Oil and Gas Majors Bring to the Table That Startups Cannot

Consider the mismatch: the market requires tens of GW of new firm power capacity. Fervo, Sage, and XGS have contracted 500, 150, and 150 MW, respectively. The entire startup sector, at maximum stretch, might deliver 2–3 GW by 2030. The market needs 45–65 GW in the US alone – a conservative estimate. This is a supply gap that only companies with major-scale capital and industrial drilling capability can fill. A single oil major entering this market with \$12–25 billion of committed capital over five years would immediately:

- Become the dominant global player in a sector currently populated by startups constrained to project-by-project fundraising – deploying more capital in a single year than the entire startup sector has raised in its history;
- Industrialize drilling costs by applying global procurement, rig fleet, and drill bit technology at scale – driving completed well costs from <\$8M to \$5–6M through the same factory-drilling learning curve that transformed shale;
- Industrialize surface facility costs by standardization

and modularization; cooling system optimization; factory procurement strategies; digital automation and remote operations to reduce the cost of ORCs from \$2500/kW to \$1250/kW. Surface facilities can amount to 50% of project capex;

- As oil majors have done for decades for LNG, negotiate portfolio-scale PPAs with hyperscalers, leveraging commercial infrastructure and balance sheet to offer the scale and counterparty quality they demand – multi-GW framework rather than project-by-project 100 MW agreements;
- Leverage existing subsurface data – decades of geophysical surveys, well logs, and temperature data across global acreage positions;
- Redeploy workforce – geoscientists, drilling engineers, and completion specialists into a growth business with 95% skill transferability.

**The geothermal sector’s total capital raised to date – approximately \$2.5–3 billion across all companies – is a rounding error by oil major standards. By way of illustration, Fervo Energy is targeting an IPO at a potential ~\$1.4 billion valuation<sup>60</sup>. A single deepwater FPSO costs \$5–6 billion.**

## The First-Mover Imperative

Hyperscaler energy procurement is moving faster than traditional oil major decision-making. Consider the deal flow in geothermal in the past 12 months alone:

- Fervo: 500 MW fully contracted (SCE, Shell Energy, Google, others), and \$421M non-recourse project finance closed (March 2026) – the first institutional debt financing for a commercial EGS project
- Sage Geosystems: 150 MW PPA with Meta
- XGS Energy: 150 MW PPA with Meta
- Google/Fervo: 115 MW via Nevada Energy
- Microsoft/G42<sup>61</sup>: 1 GW geothermal DC campus in Kenya

These deals – totaling less than 2 GW – are being captured by companies with a fraction of the capabilities of oil and gas entities. They are proving the technology and validating the market, but they cannot fill it. The startups lack the capital, global reach, drilling fleet, and execution muscle to industrialize geothermal at the scale the market demands.

The company that enters with major-scale capital in the next 18–24 months will define the standards, secure the best acreage and offtake relationships, and capture the majority of value as the sector scales from GW to tens of GW. The company that waits will find the best positions taken and the market structure set by others.



## Chapter 5

# Financing Velocity in Post-De-Risked Geothermal

## Introduction

Once hyperscaler-backed demonstration plants de-risk the subsurface and first-of-a-kind engineering, the limiting factor for next-generation geothermal shifts from technical feasibility to the speed and scale at which capital can be deployed. The key distinction is not headline cost of capital, but the deployment mechanism.

Fervo's considerable achievement to raise \$421 million in non-recourse debt proves the Cape Station EGS project has moved from de-risking to institutional financing. The oversubscribed syndication is precisely the project finance challenge described below: capital-intensive, sequential, and time-consuming. It impressively validates EGS technology and Fervo's capabilities. However, it does not solve the deployment velocity problem.

**Startups finance growth serially.** Even a well-funded company must finance expansion through discrete, limited-recourse raises. Each additional plant is re-underwritten, re-documented, and often re-syndicated with bespoke covenants, conservative drawdown conditions, and larger equity cushions. This makes growth inherently sequential and sensitive to market windows. As an example, Fervo has raised ~\$1.5 billion since inception and targets \$0.5-1.0 billion annual capex—enough for perhaps one major project per financing cycle.

**Oil majors finance growth as portfolio execution.** An investment-grade major (AA-/Aa2) treats the same post-de-risked buildout as an industrial program funded through corporate cash flow, liquidity and established

debt channels. Exxon's \$27-29 billion annual capex budget—deployed through treasury rather than project-by-project syndication—enables:

- Earlier commitment of spend with fewer sequential financing gates
- Simultaneous development across multiple locations
- 5-7-year timeline compression vs. serial fundraising
- Construction completion guarantees that no startup credit profile can provide

Sponsor backing reduces transaction friction and counterparty risk.

**For geothermal to reach tens of GW by the early 2030s—the scale demanded by data centers—only entities with major-scale capital and investment-grade credit can deploy fast enough. The startup pathway validated the technology, but cannot supply the market at the required pace.**

There is a prevailing narrative that technology risk is the primary barrier to scaling next-generation geothermal. However, as the subsurface and technologies are de-risked through demonstration projects, the critical path to commercialization shifts decisively from physics to finance. It is common practice to evaluate this next phase through the lens of the cost and availability of capital for a project. This analysis argues that doing so misses the more consequential variable: the structural mechanism of capital deployment.

**Table 9: The Financing Advantage of the Oil and Gas Major**

Metric	Oil Major (e.g., Exxon)	Startup (e.g., Fervo)
<b>Credit Rating</b>	AA- / Aa2 (Investment Grade)	Non-rated / Venture Debt
<b>Estimated WACC</b>	4.5-7.5%	12-18%+
<b>Annual Capex</b>	\$27-29B (XOM 2026 plan)	~\$0.5-1.0B
<b>1 GW Financing</b>	Single internal budget allocation	4-6 tranches of project debt/equity
<b>Deployment Model</b>	Parallel execution across sites	Serial fundraising per project

For a startup, even a successful one, scaling to multiple gigawatts remains a serial exercise in project finance—a series of discrete, high-cost credit events. For an investment-grade oil major, the same technical de-risking unlocks a fundamentally different paradigm: industrial-scale portfolio execution funded by the balance sheet. Understanding this distinction—the difference between underwriting a single asset and optimizing a corporate treasury—is essential to forecasting the true velocity at which geothermal can reach material scale.

### The Pathway to Funding Is Fundamentally Different

For a finance audience, the distinction is best understood by looking at the counterparty risk it is being asked to underwrite. When a startup approaches the market for a 1 GW project, equity and debt providers face a single-asset, thinly capitalized credit—a discrete “credit event” where returns and repayment hinge entirely on the execution of one project, with a relatively modest balance sheet to absorb delays or cost overruns.

An investment-grade major, by contrast, absorbs that same construction risk within a diversified, \$300B–\$400B total assets (XOM) with a debt-to-equity ratio of ~0.15. It can self-fund construction through corporate debt, effectively substituting the startup’s “execution risk” with a stable AA- credit profile.

For a banker, this means the financing shifts from underwriting a speculative venture to optimizing a corporate treasury function. While de-risking can remove technical uncertainty, majors uniquely remove credit, completion, and liquidity uncertainty—exactly the risks bankers underwrite on GW scale. In a de-risk scenario, the major replaces the startup’s “execution risk” with a diversified credit profile (AA- or higher), lowering the project’s Weighted Average Cost of Capital (WACC) by several hundred basis points.

### Why Oil Majors Scale Faster Post-De-Risking

The structural financing advantage of an oil major fundamentally alters the pathway to multi-GW deployment. A startup must raise project-by-project equity and negotiate limited-recourse project finance for each development, resulting in 18–36-month financing cycles and a practical ceiling on annual deployment.

In contrast, an investment-grade major can finance GW geothermal plants through direct balance sheet capex, corporate debt issuance, or portfolio-level structures that cross-collateralize assets and reduce the due diligence burden. The velocity advantage is clear:

- **Parallel Execution vs. Serial Fundraising:** A major can initiate construction on three to five 1 GW projects simultaneously because funding is allocated from a central treasury via a single board-level decision. The startup pathway requires sequential financial closings, needing 5-10 separate transactions to reach the same scale, each taking 12-24 months. This compresses the deployment timeline by an estimated 5 to 7 years.
- **Elimination of Syndication Lag:** By internalizing debt funding, the major avoids the lengthy syndication process for limited-recourse project finance. While a startup may face a prolonged period to satisfy syndicate requirements and drawdown conditions, an investment-grade sponsor can typically proceed using balance-sheet liquidity and established funding channels, reducing the chance that external financing becomes the schedule-gating item.

- **Industrial Scaling via Replication:** After the first project, a major can template the EPC framework and replicate it across a global portfolio without re-underwriting the financing structure for each new site. This transforms “bespoke” infrastructure into a manufacturing production line where the marginal cost of capital declines with each new GW.

## The “Anchor Tenant” Effect and Framework Bankability

Beyond capital availability, majors provide construction completion guarantees that startups cannot. Lenders underwrite not just the PPA, but the sponsor’s ability to deliver the asset that satisfies that PPA. An oil major’s Investment grade (AA / AA-) balance sheet effectively underwrites construction risk, lowering perceived completion risk and supporting tighter pricing and higher leverage - enabling multi-GW framework agreements that capture an entire hyperscale region’s demand in a single financial architecture - something no startup credit profile can support.

## Financing at Scale: The Major vs. Startup Advantage

Exxon’s \$27-29B annual capex budget alone exceeds the total equity that startup Fervo Energy, for example, has raised since inception by almost 20-fold, while its AA- credit rating and 0.15 debt-to-equity ratio enable self-funded construction that bypasses the project finance gauntlet entirely (Table 10). The Major’s WACC includes the benefit of internalizing construction risk, whereas the Startup’s WACC is driven by the non-recourse nature of its debt, which requires higher equity cushions.



**Table 10 : Comparative Financing Profiles (2026 Data)**

Financial Metric	Oil Major (e.g., Exxon / Chevron)	EGS Startup (e.g., Fervo Energy)
<b>Market Capitalization</b>	\$613B (XOM) (2/13/26) <sup>62</sup> \$333B (CVX) (2/13/26) <sup>63</sup>	Targeting \$2B - \$4B (Projected IPO) <sup>64</sup>
<b>Credit Rating</b>	Aa2 / AA- (XOM Investment Grade); CVX AA <sup>65</sup> Debt-to-equity ratio: 0.15; Interest coverage: 48.45x	Non-Rated / Venture Debt Profile <sup>66</sup> No public credit rating available
<b>Estimated Cost of Debt</b>	<=~3.5% (Exxon's AA-/Aa2 rating enables consistent access to public debt markets at investment-grade spreads) <sup>67,68</sup>	Venture Debt; rates typically double-digits (SOFR (3.7% on 2/12/26) plus a spread of 6% to 9%) <sup>69</sup> with warrants; exact blended rate not publicly disclosed.
<b>Estimated WACC</b>	~4.5% - 7.5% <sup>70</sup> Inferred from capital structure and IG credit metrics	~12% - 18%+ Standard range for venture/development-stage energy infrastructure <sup>71</sup>
<b>Primary Funding Source</b>	Treasury / Cash Flow (\$52B ops XOM)	Multi-Stage VC / Project Finance \$1.5 B raised since inception <sup>72</sup>
<b>Annual CAPEX Budget</b>	\$27B - \$29B (Exxon 2026 plan) <sup>73</sup>	~\$0.5B - \$1B Estimated run-rate based on total equity raised (\$556M) and build-out targets
<b>1 GW Financing Logic</b>	Single "internal" budget allocation Funded via corporate treasury; no external project-level credit events	4-6 tranches of project-level debt/equity



## Chapter 6

# Pathway To Materiality: A Phased Global Program

Geothermal energy at scale has never been deployed through the factory-drilling, portfolio-PPA model that this plan proposes.

A phased program allows each tranche of capital to de-risk the next: Phase 1 proves the drilling economics, locks in anchor offtake, and establishes cost benchmarks that give investors and partners the confidence to underwrite Phase 2's industrial scale-up – converting early project-level returns into a portfolio-grade platform valued at over \$100 billion.

### **Phase 1 (2028–2033):**

Establishes a global geothermal platform by deploying \$12–25B to build 3–5 GW across multiple regions, validating factory-scale drilling, securing hyperscaler PPAs, reducing well costs below \$6M, and achieving 10–18% project IRRs.

### **Phase 2 (2030–2038):**

Scales deployment to 25 GW total capacity with \$75–115B invested, driving down costs through industrialization while targeting 18–22% IRRs, ~\$20B annual revenue, and a >\$100B enterprise valuation.

Across both phases, the strategy combines cost reduction, workforce expansion, and technology (including AI and resource co-production like lithium and heat) to create a large-scale, diversified geothermal energy platform.

# Pathway To Materiality: A Phased Global Program

**25 GW**

Cumulative Capacity

**\$75–115B**

Capital Deployed

**\$20B/yr**

Annual Revenue

**\$100B+**

Platform Value

## Phase 1: Foundation

Target — 2033

**2028–2033 Construction**  
**3–5GW; \$12–25B Capital Deployment**

**Objective:** Establish commercial operations at scale, prove the factory-drilling model, and secure foundation offtake agreements that anchor the business.

**3–5 GW**

Target Capacity

**\$12–25B**

Capital Deployment

**10–18%**

Target IRR (post-tax, unlev.)

### Global Development Corridors

- **US West:** Utah, Nevada, New Mexico — leveraging learnings from 1st-movers
- **US Texas:** ERCOT market — constrained grid, premium pricing, surging DC demand (9.7 GW)
- **East Africa: Kenya** — existing geothermal infrastructure, hyperscaler commitment (Microsoft/G42)
- **Southeast Asia:** Japan, Indonesia, Philippines, Taiwan, S Korea — vast EGS potential, Ring of Fire
- **Europe:** Upper Rhine Graben, Pannonian Basin, UK — high electricity prices, DC grid constraints
- **MENA:** Emerging data center hubs with untapped geothermal resource

### Key Activities & Targets

- Screen and rank 8–12 global development corridors
- Pipeline of 5–8 projects (500–1,000 MW each) targeting 4 GW
- Prove commercial viability; establish benchmark for cost reduction
- De-risk reservoir performance at scale
- Validate PPA pricing durability across market cycles
- Standardize well-design, completions, and modular surface plants across all corridors
- Framework PPAs with 2+ hyperscalers (multi-GW, 15–25yr terms)
- Redeploy 1,000–2,000 subsurface professionals from upstream workforce
- Drilling R&D: stimulated & completed well costs <\$6M within 24 months

## Phase 2: Scale-Up & Industrialization

Target — 2038

**2030–2038 Construction**  
**Cumulative 25 GW; \$75–115B Capital Deployment (Phases 1 & 2)**

**Objective:** Drive cost from \$4,000–5,000/kW to \$3,000–4,000/kW by 2035, establish geothermal as a core business segment rivaling upstream in scale, and deliver infrastructure-grade returns.

**25 GW**

Cumulative by 2038

**\$75–115B**

Total Capex (Ph 1 + 2)

**14–27%**

Target IRR (post-tax, unlev.)

### Deployment & Cost Trajectory

- Deploy 2–3 GW annually across 5–8 global corridors
- Capex: \$4,000–5,000/kW (2030) → \$3,000–4,000/kW (2035) → \$2,000–3,000/kW (2040)
- Well costs: <\$8M → \$5–6M → \$4–5M via factory drilling & automation
- Portfolio PPAs: 15–25yr terms, \$100–180/MWh
- Portfolio-weighted avg IRR: 18–22%
- Top-quartile capital allocation opportunity
- Returns competitive with upstream; superior revenue certainty
- Transition from project finance to investment-grade metrics

### Strategic Outcomes

- \$20B annual gross revenue by late-2030s
- Standalone P&L — reportable business segment
- Adjacent: lithium extraction, district heating, industrial heat
- AI-driven production optimization & reservoir management
- Platform value: \$100B+ (8–12x EBITDA on contracted flows)
- Workforce: expand to 4,000–8,000 professionals globally
- Strategic asset for energy transition positioning
- Geothermal as segment rivaling upstream in scale

### Cost Trajectory

**2025–2028**

\$6,000–8,000/kW

**2028–2033**

\$4,000–5,000/kW

**2033+**

\$3,000–4,000/kW

Source: Chapter 6 — Pathway To Materiality: A Phased Global Program



## Chapter 7

# Conclusion: The Case For Action

The convergence of AI-driven power demand, geothermal cost reduction, and the oil and gas industry's subsurface mastery creates a time-bound strategic opportunity. To summarize:

- **The market is real:** 45–65 GW of incremental firm capacity required in the US alone by 2030, with equivalent-scale demand emerging in Europe and Asia-Pacific. The Hyperscaler demand dynamic means the total addressable market for firm power is expanding, not fixed – and geothermal grows the pie rather than competing for a slice.
- **US and international pricing supports material returns:** \$100–180/MWh globally deliver 10–18% project IRRs in Phase 1 (Construction 2028–2033), scaling to 14–27% in Phase 2 (Construction 2030–2038) as industrialization reduces capex from \$4,000–5,000/kW to \$3,000–4,000/kW, with 15–25-year revenue visibility. US base-case pricing of \$100–115/MWh delivers 11–14% (Phase 1) and 15–21% (Phase 2), while premium markets (Taiwan, Europe) reach 18% (Phase 1) and up to 27% (Phase 2).
- **The capital is competitive:** \$75–115 billion over a decade for 25 GW compares directly with the sustaining capital required for equivalent-revenue upstream programs – but with contracted rather than commodity-exposed revenue.
- **The risk profile is superior:** Contracted revenue, managed decline far below upstream rates, zero fuel cost, and investment-grade counterparties

vs. commodity-exposed, steeply declining, price-volatile upstream production.

- **The capability fit is precise:** Drilling, completions, subsurface characterization, and megaproject execution are your century-old core competencies – and the primary barrier to entry for every other potential entrant.
- **The window is finite:** Startups have proven the technology at hundreds of MW. Hyperscalers are contracting now. But only companies with major-scale capital can industrialize geothermal at the tens-of-GW scale the market demands. The companies that move first will define the standards, secure the best resources and offtake, and capture the majority of value.
- **The scale of ambition must match the scale of the opportunity.** Fervo, SAGE and XGS are building for 500, 150 and 150 MW with startup capital, respectively. A single oil major should target an order of magnitude more. Several majors could together deliver 50+ GW by the late-2030s – transforming the geothermal industry from a niche into a pillar of the global power system, and generate >\$40B in annual contracted revenue.

### Recommended Actions For Majors:

1. **Internal alignment:** Brief the Capital Allocation and Strategy committees on this analysis. Commission internal technical due diligence on 3–5 target

corridors. Model the portfolio economics of a \$12–25 billion first-phase commitment against existing capital allocation alternatives.

**2. External engagement:** Authorize direct discussions between your business development team and hyperscaler energy procurement leads – specifically Microsoft’s 24/7 CFE team, Google’s Energy & Climate team, Meta’s Clean Technology Innovation group, and Amazon’s Energy team. Explore the appetite for multi-GW portfolio-scale framework agreements that only a major’s balance sheet can underwrite.

The question is not whether firm, low emission power will become a material energy market – the hyperscaler procurement evidence settles that. The question is not whether oil and gas capabilities are relevant – the technology overlap is self-evident. The question is not whether 500 MW is achievable – five year old startups are already doing it.

**The question is whether oil and gas entities will build the 25 GW business that the market demands, that oil and gas capabilities uniquely enable, and that hyperscaler demand for compute will fund – or whether the oil majors will watch others capture a market that is custom built for the legacy strengths of the industry.**

# POST-SCRIPT: THE 2026 IRAN CONFLICT AND THE INVESTMENT CASE FOR GEOTHERMAL

## Executive Summary

The 2026 Iran conflict strengthens rather than weakens the geothermal investment case. The disruption to oil and LNG flows through the Strait of Hormuz, together with damage to Qatar's export infrastructure, exposed how vulnerable many power systems remain to geopolitical shocks. In the markets where geothermal is most attractive – especially Europe and Asia-Pacific – that means higher gas-linked power prices, a greater premium on secure domestic generation, and a clearer advantage for energy sources that do not depend on imported fuel. Geothermal therefore offers not only firm 24/7 power, but also resilience: once built, it is local, fuel-free, and insulated from the kinds of supply disruptions that can rapidly drive-up electricity costs and increase energy security risks.

## Introduction

The core analysis in this report was substantially complete before the outbreak of hostilities between the United States, Israel, and Iran on 28 February 2026. The conflict's consequences for global energy markets – the functional closure of the Strait of Hormuz, the partial destruction of Qatar's LNG export infrastructure, and the resulting surge in oil and gas prices – are sufficiently material to this investment thesis to require direct analysis. This post-script assesses the implications across three dimensions: the effect on upstream oil and gas IRRs relative to geothermal; the effect on power prices in geothermal's target markets; and the implications of the conflict for the energy security premium embedded in geothermal's value proposition.

## The Market Context

The IEA has characterized the conflict as creating "the largest supply disruption in the history of the global oil market," with its Executive Director Fatih Birol describing it as "the greatest threat to global energy security in history."<sup>74</sup> Iran's closure of the Strait of Hormuz – through which around 25% of global seaborne oil trade and almost one-fifth of global LNG trade transited in 2025<sup>75</sup> – removed an estimated 10 million barrels per day of Gulf production from accessible markets within a fortnight of hostilities commencing, with the IEA's March 2026 Oil Market Report projecting global oil supply to fall by 8 million barrels per day in March alone.<sup>76</sup> Brent crude, which traded at approximately \$70/bbl before hostilities,

increased to almost \$120/bbl before easing to approximately \$92/bbl at the time of the IEA's March 2026 report – still \$20/bbl above its pre-war level.<sup>77</sup> On 11 March, IEA member countries unanimously agreed to release 400 million barrels of oil from emergency reserves – the largest coordinated stock draw in the Agency's history – in acknowledgement that the disruption exceeded any previous market shock.<sup>78</sup>

QatarEnergy halted all LNG production on 2 March 2026 as tanker traffic through the Strait collapsed, and declared force majeure on affected buyers on 4 March.<sup>79</sup> On 18–19 March, Iranian missile strikes on the Ras Laffan Industrial City damaged two of Qatar's 14 LNG trains and one of the two trains at the Pearl GTL facility.<sup>80</sup> QatarEnergy's CEO and Minister of State for Energy Affairs confirmed that the strikes eliminated 17% of Qatar's LNG export capacity – 12.8 million tonnes per annum – with repairs requiring three to five years, and stated that the damage would compel QatarEnergy to declare force majeure for up to five years on some long-term LNG contracts affecting counterparties in Italy, Belgium, South Korea, and China; ExxonMobil holds a 34% stake in the damaged Train S4 and a 30% stake in Train S6.<sup>81</sup> In Europe, Dutch TTF gas benchmarks climbed above €60/MWh in early trading on 3 March – a level not seen since early 2025<sup>82</sup> – against a backdrop of European gas storage entering the conflict at below 30% capacity, its lowest seasonal level in years following a harsh 2025–2026 winter.<sup>83,84</sup> In Asia, the Japan-Korea Marker – Asia's primary LNG spot benchmark published by S&P Global Platts – spiked approximately 50% between 27 February and 9 March 2026.<sup>85</sup> The European Central Bank (ECB), at its Governing Council meeting on 19 March, held rates unchanged while explicitly citing the war as making "the outlook significantly more uncertain, creating upside risks for inflation and downside risks for economic growth"<sup>86</sup>; it revised its 2026 eurozone headline inflation forecast upward to 2.6% and cut its 2026 GDP growth projection to 0.9%, a downward revision of 0.3 percentage points attributable to the war's impact on commodity markets, real incomes, and confidence.<sup>87</sup>

## Impact of Higher O&G Pricing on Geothermal's Competitive Position in the Capital Queue

The thesis that elevated oil and gas prices raise the IRRs of competing upstream investments is materially weaker than it first appears, for three reasons.

First, oil major capital allocation committees do not reprice long-cycle upstream commitments – deepwater FPSOs, new oil sands phases, major frontier programs – on the basis of a war-driven spike carrying acute reversal risk. The projects that most directly compete with geothermal in the capital queue described in Chapter 2 are precisely those with investment cycles measured in years, where the durability of any price signal matters as much as its level. Analysts have explicitly cautioned that investors are likely to remain skeptical about committing to multi-year upstream projects in response to sudden, possibly temporary, price spikes.<sup>88</sup>

Second, the conflict simultaneously imposes costs on oil major operations that partially offset the revenue uplift from higher prices. ExxonMobil – one of the reference majors throughout this report – is directly exposed through its equity stakes in the two damaged Qatari LNG trains.<sup>89</sup> Supply chain inflation, elevated insurance costs for Gulf-region operations, and the macroeconomic headwinds from a conflict the ECB has cited as creating recession risks for energy-intensive economies<sup>90</sup> all erode the net benefit to upstream capital programs.

Third, the one upstream category where a price signal does translate quickly into incremental investment, short-cycle US shale, this report identifies as structurally least attractive regardless of oil price: 35–40% first-year decline rates that demand continuous high-intensity drilling activity just to maintain plateau production. A higher oil price delays the point at which that treadmill becomes uneconomic; it does not change its nature.

### **Impact of Higher Gas Pricing on Geothermal IRRs in Target Markets**

The positive impact is more direct than the upstream effect because the transmission mechanism is structural rather than behavioral. In every premium jurisdiction modeled in this report – Europe, Japan, South Korea, and Taiwan – wholesale and contracted power prices are set at the margin by gas-fired generation. When LNG prices surge, power market clearing prices rise in parallel, and the benchmarks against which geothermal PPAs are negotiated move with them.

The critical analytical point is this is not a temporary cyclical effect. With 12.8 million tonnes per annum of Qatari LNG capacity confirmed offline for three to five years,<sup>91</sup> and no meaningful spare global liquefaction capacity available to offset the loss – Wood Mackenzie having warned that replacement volumes cannot be brought online quickly enough to offset a prolonged

outage<sup>92</sup> – the elevated pricing environment will persist well into the 2028–2033 construction window for Phase 1 geothermal projects. The PPA price ranges modeled in this analysis (\$105–160/MWh for Europe, \$135–155/MWh for Japan, \$120–180/MWh for Taiwan) should be treated as conservative floors for contracts being negotiated in current market conditions rather than central estimates. This analysis retains those original assumptions in all modeled scenarios in order to preserve comparability with the core report.

The US market presents a more muted but real analog. American domestic gas supply is insulated from the Gulf disruption by production depth and reserve capacity, but the IEA has confirmed that global LNG supply has been reduced by approximately 20% due to the conflict.<sup>93</sup> Higher global LNG netbacks increase the economic pull of US export terminals, drawing incremental volumes from domestic supply and exerting upward pressure on Henry Hub. The more consequential US dimension is the opportunity cost effect: higher domestic gas prices raise the relative value of geothermal capacity that would otherwise be displaced by gas generation in ERCOT and other US markets, strengthening the power price outlook without requiring any assumption about whether current Henry Hub levels persist.

### **The Energy Security Premium**

The most significant implication of the conflict for this investment thesis is none of the above. The energy security value proposition at the core of geothermal's case in Asia-Pacific markets – articulated in this report as a premium derived from structural LNG import dependence – has been empirically revealed at catastrophic scale in the space of six weeks.

Japan, South Korea, and Taiwan – three of the four markets generating the highest modeled IRRs in this analysis – are each among the counterparties on whose LNG contracts QatarEnergy has declared force majeure.<sup>94,95</sup> Taiwan, the highest-IRR jurisdiction in this report, holds a maximum LNG storage capacity of only eleven days of supply – the lowest in East Asia – with more than one-third of its LNG imports transiting the Strait of Hormuz, exposing its semiconductor-dependent power grid to acute disruption.<sup>96</sup> These are not abstract supply chain risks: they are the materialization, in real time, of precisely the scenario this report identifies as the central driver of geothermal's willingness-to-pay premium in the Asia-Pacific region. A 20-year geothermal PPA in any of these jurisdictions offers something no LNG-fired generator can: zero Hormuz exposure, zero force majeure risk arising from Middle Eastern conflict, and zero fuel cost across any price environment. The willingness-to-pay for those

characteristics has been permanently and visibly re-rated by events since 28 February 2026. The IEA's characterization of this as "the greatest threat to global energy security in history"<sup>97</sup> will be invoked in energy procurement discussions across the Asia-Pacific region for the duration of any policy planning horizon relevant to geothermal investment.

## Conclusion

The two principal effects of the conflict – higher upstream IRRs and higher power market IRRs – do not cancel out and do not disadvantage geothermal. The power pricing uplift is structural in duration, concentrated in this report's highest-IRR markets, and already embedded in current contract negotiations. The upstream IRR uplift is real but cyclically uncertain, concentrated in short-cycle assets that are structurally less relevant to the capital redeployment argument, and partially offset by the operational and macroeconomic headwinds the same conflict imposes on the relevant oil majors. The conflict does not alter the fundamental investment thesis presented in this report. It compresses the decision timeline and raises the cost of inaction. The question posed in this report's conclusion remains unchanged. The circumstances in which it must be answered have become more urgent.



# Appendix A: Firm Power Pricing Benchmarks by Jurisdiction

## Firm Power Pricing Benchmarks by Jurisdiction

In 2026, the market for “firm” carbon-free energy (CFE) is increasingly defined by the premiums data center operators are willing to pay to achieve hourly matching (24/7 CFE). Geothermal projects, acting as baseload equivalent to nuclear, are striking prices significantly above standard variable renewable rates. Table 12 summarizes the defensible price ranges used in the IRR modeling above, with detailed justification for each jurisdiction provided in the sections that follow.

### United States

The United States has emerged as the clearest revealed-price market for corporate demand for firm, carbon-free power, driven primarily by hyperscale data center load growth and explicit 24/7 carbon-free electricity (CFE) procurement targets.

The most salient price anchor is Microsoft’s long-term power purchase agreement with Constellation to restart the former Three Mile Island Unit 1 nuclear facility (now the Crane Clean Energy Center). Multiple independent analyst estimates place the contracted price between \$98/MWh and \$115/MWh for the 20-year agreement: Jefferies estimates \$110–115/MWh, while Morgan Stanley estimates \$98/MWh.<sup>98,99,100</sup> This pricing

is materially above prevailing wind and solar PPAs, which typically clear near \$50–60/MWh in comparable regions.<sup>101</sup> The higher pricing reflects both the scarcity value of always-on, dispatchable, zero-carbon generation and the \$1.6 billion capital investment required to restart the shuttered facility and deliver reliable 24/7 generation.<sup>102</sup> Additional market evidence supports this pricing range. Meta’s 20-year PPA with Constellation for the Clinton Clean Energy Center is estimated by Jefferies at \$70–80/MWh, representing the lower bound for existing nuclear capacity that does not require restart capital investment.<sup>103,104</sup> The spread between these transactions—Meta’s Clinton deal (\$70–80/MWh) and Microsoft’s Three Mile Island restart (\$98–115/MWh)—effectively brackets the price range for firm, zero-carbon baseload power in the U.S. market.

Importantly, these transactions demonstrate that large corporate buyers are willing to contract at triple-digit prices for firm supply when it materially reduces grid exposure, balancing costs, and carbon accounting complexity. From a functional standpoint, geothermal provides identical reliability characteristics—24/7 availability, high-capacity factors ( $\geq 90\%$ ), and long asset life—placing it squarely within the same procurement category as nuclear rather than variable renewables.

While the observed nuclear market spans \$70–115/MWh (with existing capacity at the lower end), \$100/MWh represents a defensible floor for long-term geothermal PPAs serving data centers in the U.S. market, with upside to \$115/MWh where projects provide locational,

congestion, or resilience benefits, or where they involve greenfield development comparable to nuclear restart capital requirements.

## Europe & United Kingdom

Across Europe, firm power pricing is increasingly shaped by three structural factors: elevated carbon prices, tightening dispatchable capacity margins, and the rapid expansion of hyperscale data centers in regions with limited grid flexibility.

While the UK's Hinkley Point C nuclear project remains the most transparent single benchmark for firm, zero-carbon baseload pricing, it should be understood as a price anchor rather than a UK-specific outlier. Originally contracted at £92.50/MWh (2013 prices), indexation has raised the effective strike price to approximately £130–135/MWh by the mid-2020s (\$160–170/MWh) reflecting the system value of long-duration, always-available clean power under high carbon and reliability constraints.<sup>105,106</sup> This figure represents the government's revealed willingness to pay for firm, zero-carbon baseload power over a multi-decade horizon.

On the European continent, similar pricing signals emerge through a different mechanism: the cost of firming variable renewables to meet industrial reliability standards. Analysis by CRU Group indicates that supplying data centers with ~98% hourly availability using wind, solar, and storage in markets such as Germany, the Netherlands, and Ireland results in system-level costs approaching \$145–150/MWh, once overbuild, long-duration storage, and carbon pricing are incorporated.<sup>107</sup> This is particularly relevant in the Benelux and German markets, where grid congestion, permitting delays, and limited storage duration materially increase balancing costs.

Data center siting trends reinforce this dynamic. Northern Europe (Ireland, Denmark, Sweden) and the Benelux region offer favorable cooling conditions and network connectivity but face binding grid constraints and rising curtailment risk, while Southern European markets (Spain, Italy) benefit from abundant renewables yet require significant firming to achieve 24/7 supply. In both cases, the marginal cost of reliability—not energy—sets the clearing price for power procured by hyperscale operators.

Against this backdrop, geothermal priced in the \$105–160/MWh range is best understood not as a premium renewable, but as a cost-competitive substitute for nuclear and firming renewable portfolios across Europe. Its value is highest in congested or weakly interconnected

regions, where firm domestic generation can defer grid upgrades, reduce balancing exposure, and support long-term data center expansion.

## Japan

Japan represents one of the world's most structurally constrained markets for firm, non-fossil electricity, owing to its heavy reliance on imported LNG, limited interconnection, and the slow pace of nuclear restarts following Fukushima.

Government energy planning documents from Japan's Ministry of Economy, Trade and Industry (METI) explicitly frame nuclear and other firm non-fossil resources as essential to energy security, acknowledging that renewables alone cannot stabilize the system.<sup>108</sup> At the same time, Japan's wholesale electricity prices and industrial tariffs remain among the highest in OECD countries, reflecting fuel import exposure and system rigidity. While exact LCOE figures for new nuclear in Japan vary by assumption, international estimates consistently place them in the \$120–150/MWh range, before accounting for scarcity and security premiums. Historical Japanese feed-in tariffs for non-fossil baseload resources also cleared at levels materially above global renewable averages, reinforcing the presence of a long-standing willingness to pay for firm supply – with rates for geothermal under prior schemes clearing at ¥26/kWh (\$170–180/MWh at then-prevailing exchange rates).<sup>109</sup> In this context, geothermal PPAs in the \$135–155/MWh range are consistent with both historical policy signals and current market fundamentals. For data centers and industrial buyers, geothermal offers a domestic, fuel-free hedge against LNG price volatility and supply disruption, making it a direct analogue to nuclear in procurement decisions.

## Taiwan

Taiwan represents a structurally premium market for firm geothermal power, driven by nuclear phase-out, heavy LNG import dependence, and rapidly growing hyperscale data center demand.

Taiwan's Ministry of Economic Affairs (MOEA) has established some of the highest geothermal feed-in tariffs globally for 2026, explicitly recognizing geothermal as a strategic domestic baseload resource. Published FITs range from NT\$4.92–5.96/kWh (\$156–188/MWh) for conventional geothermal and up to NT\$8.855/kWh (~\$280/MWh) for next-generation systems<sup>110</sup>. These values represent an upper bound of

political and system willingness-to-pay, not marginal project costs.

The often-cited \$90-92/MWh figure for Taiwan does not represent the price of firm geothermal power. It originates from system-level modeling of achieving ~80% hourly carbon-free electricity (24/7 CFE) using a diversified portfolio of renewables, grid imports, and limited firm resources.<sup>111</sup> As such, it reflects a blended average cost, not the marginal value of scarce, always-on domestic supply.

Importantly, even this modeled average is already competitive with – and in some cases below – current industrial tariffs following recent 15-25% electricity price increases for data centers.

When geothermal is procured as dedicated, firm baseload power – displacing LNG exposure and reducing grid and geopolitical risk – modeling and international comparables support bilateral PPA pricing in the \$120-180/MWh range. This aligns Taiwan more closely with Japan-style scarcity pricing than with Southeast Asian renewable benchmarks.

For hyperscale operators pursuing 24/7 CFE, energy security, and long-term cost certainty, geothermal occupies a distinct procurement category, comparable to nuclear rather than wind or solar. In Taiwan, geothermal should be valued not as a low-cost renewable, but as critical national infrastructure. Pricing below ~\$120/MWh risks understating both its scarcity value and its role in insulating data centers from fuel price volatility, supply chain disruption, and grid reliability constraints.

## South Korea

South Korea's electricity market is undergoing a period of structural adjustment driven by rapid ICT and AI-driven load growth, rising fuel costs, and increasing recognition of grid stability constraints. Although the government continues to target large-scale renewable deployment, official policy documents acknowledge that firm generation capacity remains necessary to maintain reliability. As a result, South Korea has revived plans for new nuclear reactors and extended the operating lives of existing units. These decisions implicitly set a benchmark for the value of firm, low-carbon power in the Korean system.

At the same time, industrial electricity tariffs have undergone repeated upward adjustments, with differentiated pricing that increasingly penalizes peak

and nighttime usage. Public disclosures by KEPCO confirm that large industrial consumers—including data centers—are facing materially higher effective power costs than in prior years.<sup>112</sup> Within this environment, geothermal priced at \$105-125/MWh functions as a risk-management instrument rather than a marginal energy purchase. By providing stable, 24/7 output, geothermal can hedge tariff volatility, reduce balancing exposure, and align with Korea's long-term reliability planning, placing it competitively against nuclear-equivalent alternatives.

**Table 12 : Firm Power Price Ranges by Jurisdiction (2026)**

Jurisdiction	Price Range (\$/MWh)	Market Benchmark	Key Driver
<b>USA</b>	\$100.00 – \$115.00	Microsoft-Constellation Three Mile Island Nuclear PPA (\$98–\$115/MWh) <sup>113,114,115</sup> ; Meta-Constellation Clinton Nuclear PPA (\$70–\$80/MWh) <sup>116,117</sup>	Scarcity value of firm, dispatchable, zero-carbon baseload. Hyperscale buyers paying ~2× wind/solar PPAs (\$50–60/MWh) for 24/7 CFE matching, grid independence, and elimination of balancing risk.
<b>Europe / UK</b>	\$105.00 – \$160.00	Hinkley Point C Inflation-Adjusted Strike <sup>118,119</sup> and Firmed Renewables Portfolio Cost (\$145–150/MWh) <sup>120</sup>	Cost of reliability and 24/7 availability. High carbon prices, grid congestion, and balancing costs to firm intermittent renewables for industrial baseload.
<b>Japan</b>	\$135.00 – \$155.00 {FIT: \$170–\$180/MWh}	New Nuclear LCOE (\$120–\$150/MWh) <sup>121</sup> plus Historical Non-Fossil FITs <sup>122</sup> ; Highest OECD Industrial Power Tariffs <sup>123</sup>	Extreme import dependence (LNG). Energy security premium for domestic, fuel-free firm generation post-Fukushima. Geothermal as nuclear substitute in constrained, high-price market.
<b>Taiwan</b>	PPA: \$120 – \$180 {FIT: \$156 – \$280}	MOEA Geothermal FITs: \$156–\$188/MWh (conventional), up to \$280/MWh (next-gen systems) <sup>124</sup> ; Bilateral PPA modeling for firm baseload <sup>125</sup>	Nuclear phase-out + LNG import dependence. Geothermal positioned as critical national infrastructure and nuclear substitute. Energy security, grid independence, and insulation from fuel price volatility for hyperscale data centers.
<b>South Korea</b>	\$105.00 – \$125.00	KEPCO Industrial Tariff Adjustments. <sup>126</sup> Nuclear Reactor Revival Plans <sup>127</sup>	Grid reliability mandates firm capacity. Nuclear revival sets implicit benchmark for firm, low-carbon power value. Data centers facing materially higher costs with differentiated peak pricing—geothermal provides 24/7 hedge against tariff volatility and balancing risk.



## Appendix B: Geothermal Investability in Industrialized Economies

### Geothermal Investability in Industrialized Economies

Large-scale geothermal power generation in industrialized markets can deliver post-tax unlevered project IRRs of **10%–27%** across two deployment phases, positioning it as one of the most attractive non-upstream investment opportunities available to energy companies in the current decade.

#### Phase 1 (2028-2033): Initial Scale Deployment

- Target capacity: 4 GW
- Capital intensity: \$4,000–5,000/kW (early learning curve)
- Project Post-Tax IRRs: **10%–18%** depending on jurisdiction and PPA pricing
- Strategic objective: Prove commercial viability, establish supply chains, validate factory-drilling model

#### Phase 2 (2030-2038): Mature Scale Deployment

- Target capacity: 21 GW (cumulative 25 GW)
- Capital intensity: \$3,000–4,000/kW (mature learning curve)
- Project Post-Tax IRRs: **14%–27%** depending on jurisdiction and PPA pricing

- Strategic objective: Achieve oil-major-scale returns through industrialization and cost reduction

This return profile reflects a fundamental market shift: geothermal is no longer competing against variable renewables on marginal energy cost, but is being procured as firm, dispatchable baseload power—functionally equivalent to nuclear—by hyperscale data centers pursuing 24/7 carbon-free electricity targets. The resulting pricing environment bears little resemblance to wind or solar PPAs. Instead, recent transactions—most notably Microsoft’s \$100–115/MWh nuclear restart agreement with Constellation—reveal corporate willingness to pay triple-digit prices for always-on, zero-carbon generation that eliminates grid exposure and balancing risk.

The analysis that follows quantifies project economics across five key jurisdictions (USA, Europe, Japan, South Korea, Taiwan) where data center growth, grid constraints, and energy security imperatives are converging to create sustained demand for firm clean power. For each market, we establish defensible PPA ranges anchored to nuclear strike prices, firmed renewable costs, and revealed government willingness-to-pay, then model project returns across both deployment phases.

### Key assumptions:

- **Phase 1 (Construction commences 2028, ramping from 2031 to 2033):** 0.5-1 GW+ projects co-located with data centers; capex range \$4,000-5,000/kW reflecting early-stage learning curve; 4 GW total deployment
- **Phase 2 (Construction commences 2030, ramping from 2033 to 2038; 2.5 years construction per module):** Continued 1 GW+ projects; capex range \$3,000-4,000/kW reflecting industrial scale and supply chain maturation; 21 GW additional deployment (25 GW cumulative)
- All returns are post-tax, unlevered, and 2% inflation-indexed
- 95% capacity factor
- Base Case Annual Costs: 3.5% of capex - comprising 2% of capex for O&M and 1.5% of capex for annualised sustaining capex.
- 45-year project life with managed decline profile mitigated by continuous drilling and workovers (Gross power decline 1-3% pa, net decline after sustaining program: 0.5% pa).

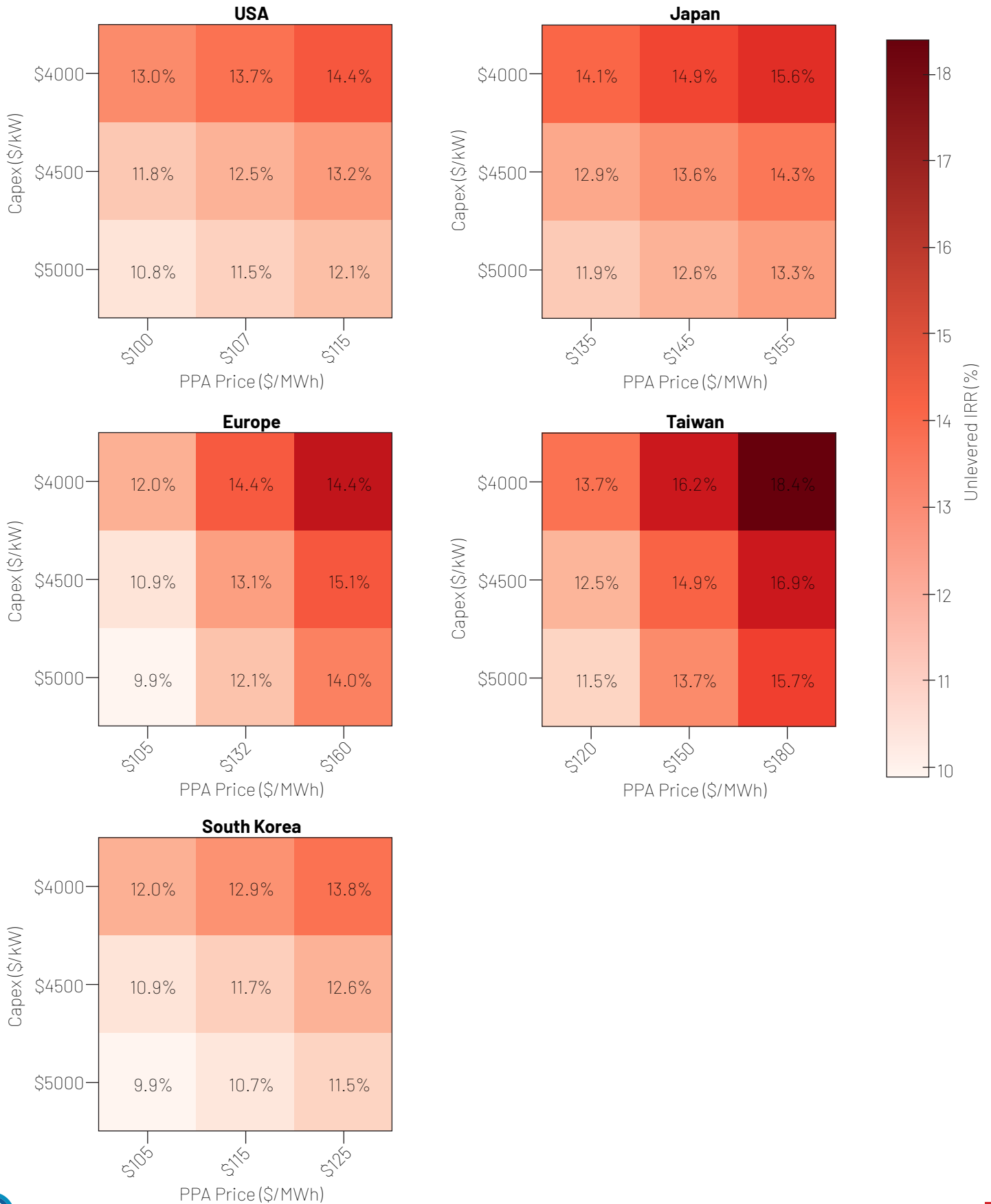
These unlevered returns represent project-level economics before financing decisions, making them directly comparable to upstream development opportunities and allowing flexible capital structure optimization.

The combination of structural power market evolution, proven regulatory frameworks, and maturing drilling technology has created a narrow but significant window for scaled geothermal investment. **Phase 1 establishes the platform; Phase 2 delivers oil-major-scale returns** that compare favorably to traditional upstream development—without commodity price exposure.

The IRR ranges presented in Figure 1 and Table 13 (Phase 1), and Figure 2 and Table 14 (Phase 2) below are derived from two inputs: realistic capital cost scenarios and defensible power purchase agreement prices for each jurisdiction. These PPA prices are anchored to observable market transactions, nuclear strike prices, and government-revealed willingness to pay for firm, zero-carbon baseload power. The detailed pricing methodology and jurisdiction-specific benchmarks follow the sensitivity analysis.

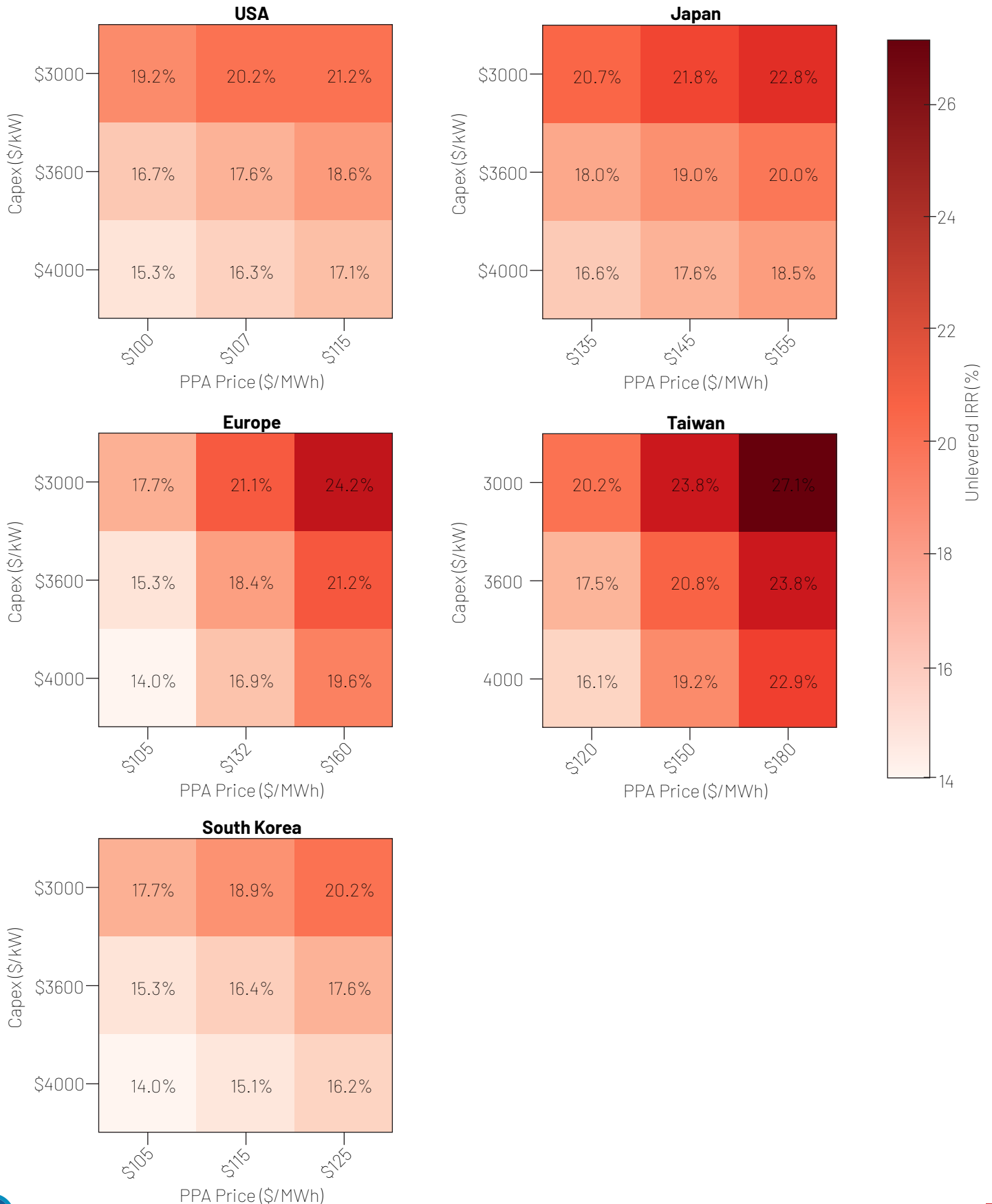
### Figure 1 : Phase 1 Geothermal IRR Heat Maps

#### Geothermal Project IRR Sensitivity Analysis Unlevered Returns by Country, Capex and PPA Price



## Figure 2 : Phase 2 Geothermal IRR Heat Maps

### Geothermal Project IRR Sensitivity Analysis Unlevered Returns by Country, Capex and PPA Price



**Table 13 : IRR Sensitivity Analysis (PPA and Capex/ kW): Phase 1: 4 GW construction start 2028**

Country	PPA Scenario	PPA Price 2026	Capex Scenario	Capex (\$/kW)	IRR (%)	Tax Rate	ITC	Inflation Indexed
USA	Low PPA	\$100	Low	4000	13.00%	21%	30%	Yes
USA	Low PPA	\$100	Base	4500	11.80%	21%	30%	Yes
USA	Low PPA	\$100	High	5000	10.80%	21%	30%	Yes
USA	Mid PPA	\$107	Low	4000	13.70%	21%	30%	Yes
USA	Mid PPA	\$107	Base	4500	12.50%	21%	30%	Yes
USA	Mid PPA	\$107	High	5000	11.50%	21%	30%	Yes
USA	High PPA	\$115	Low	4000	14.40%	21%	30%	Yes
USA	High PPA	\$115	Base	4500	13.20%	21%	30%	Yes
USA	High PPA	\$115	High	5000	12.10%	21%	30%	Yes
Japan	Low PPA	\$135	Low	4000	14.10%	30%	-	Yes
Japan	Low PPA	\$135	Base	4500	12.90%	30%	-	Yes
Japan	Low PPA	\$135	High	5000	11.90%	30%	-	Yes
Japan	Mid PPA	\$145	Low	4000	14.90%	30%	-	Yes
Japan	Mid PPA	\$145	Base	4500	13.60%	30%	-	Yes
Japan	Mid PPA	\$145	High	5000	12.60%	30%	-	Yes
Japan	High PPA	\$155	Low	4000	15.60%	30%	-	Yes
Japan	High PPA	\$155	Base	4500	14.30%	30%	-	Yes
Japan	High PPA	\$155	High	5000	13.30%	30%	-	Yes
S. Korea	Low PPA	\$105	Low	4000	12.00%	25%	-	Yes
S. Korea	Low PPA	\$105	Base	4500	10.90%	25%	-	Yes
S. Korea	Low PPA	\$105	High	5000	9.90%	25%	-	Yes
S. Korea	Mid PPA	\$115	Low	4000	12.90%	25%	-	Yes
S. Korea	Mid PPA	\$115	Base	4500	11.70%	25%	-	Yes
S. Korea	Mid PPA	\$115	High	5000	10.70%	25%	-	Yes
S. Korea	High PPA	\$125	Low	4000	13.80%	25%	-	Yes

Country	PPA Scenario	PPA Price 2026	Capex Scenario	Capex (\$/kW)	IRR (%)	Tax Rate	ITC	Inflation Indexed
S. Korea	High PPA	\$125	Base	4500	12.60%	25%	-	Yes
S. Korea	High PPA	\$125	High	5000	11.50%	25%	-	Yes
Europe	Low PPA	\$105	Low	4000	12.00%	25%	-	Yes
Europe	Low PPA	\$105	Base	4500	10.90%	25%	-	Yes
Europe	Low PPA	\$105	High	5000	9.90%	25%	-	Yes
Europe	Mid PPA	\$132	Low	4000	14.40%	25%	-	Yes
Europe	Mid PPA	\$132	Base	4500	13.10%	25%	-	Yes
Europe	Mid PPA	\$132	High	5000	12.10%	25%	-	Yes
Europe	High PPA	\$160	Low	4000	16.40%	25%	-	Yes
Europe	High PPA	\$160	Base	4500	15.10%	25%	-	Yes
Europe	High PPA	\$160	High	5000	14.00%	25%	-	Yes
Taiwan	Low PPA	\$120	Low	4000	13.70%	20%	-	Yes
Taiwan	Low PPA	\$120	Base	4500	12.50%	20%	-	Yes
Taiwan	Low PPA	\$120	High	5000	11.50%	20%	-	Yes
Taiwan	Mid PPA	\$150	Low	4000	16.20%	20%	-	Yes
Taiwan	Mid PPA	\$150	Base	4500	14.90%	20%	-	Yes
Taiwan	Mid PPA	\$150	High	5000	13.70%	20%	-	Yes
Taiwan	High PPA	\$180	Low	4000	18.40%	20%	-	Yes
Taiwan	High PPA	\$180	Base	4500	16.90%	20%	-	Yes
Taiwan	High PPA	\$180	High	5000	15.70%	20%	-	Yes

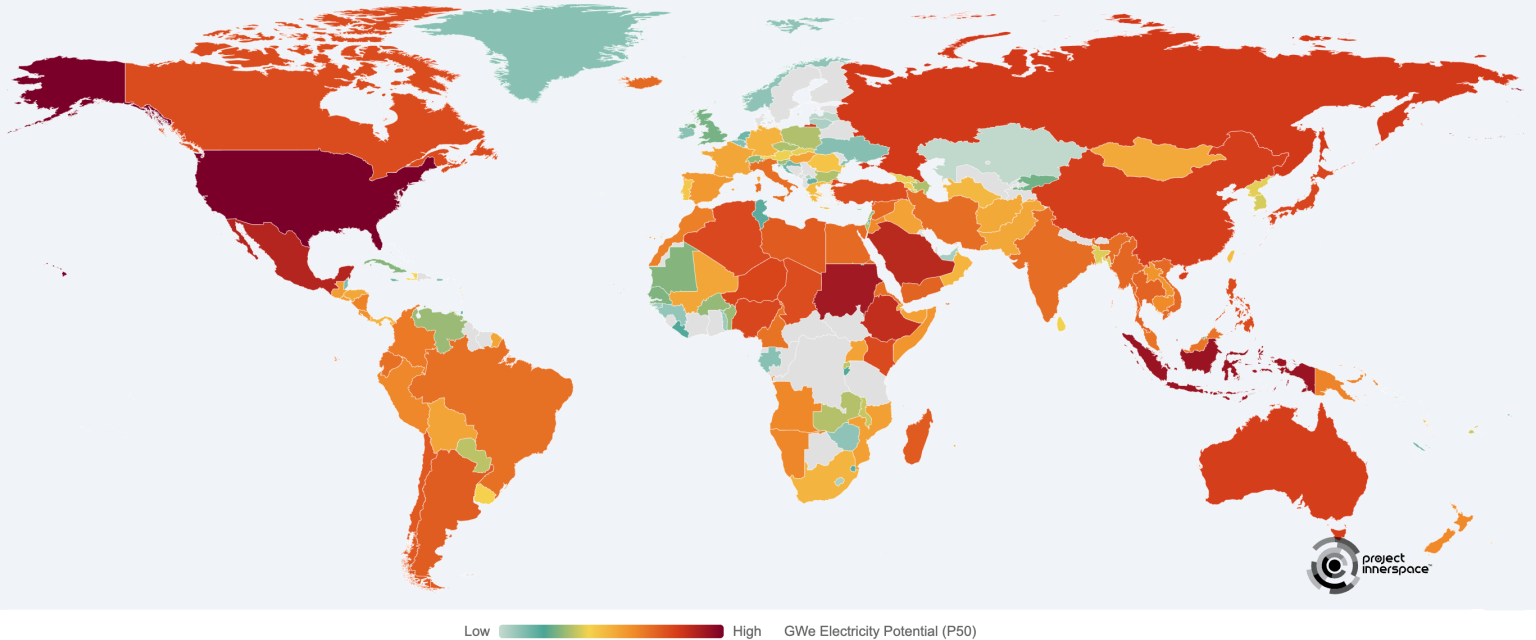
Note: The 30% Investment Tax Credit (ITC) for the USA reflects the Inflation Reduction Act's enhanced credit for domestic clean energy projects meeting prevailing wage and apprenticeship requirements. For Taiwan, the MOEA \$280/MWh FIT ceiling for next-generation systems represents substantial additional upside not modeled here. Phase 1 unlevered IRRs would be in the mid- to high-twenties, representing the highest-returning single jurisdiction in this entire analysis.

**Table 14 : IRR Sensitivity Analysis (PPA and Capex/ kW): Phase 2: 21GW construction start 2030**

Country	PPA Scenario	PPA Price 2026	Capex Scenario	Capex (\$/kW)	IRR (%)	Tax Rate	ITC	Inflation Indexed
USA	Low PPA	\$100	Low	3000	19.20%	21%	30%	Yes
USA	Low PPA	\$100	Base	3600	16.70%	21%	30%	Yes
USA	Low PPA	\$100	High	4000	15.30%	21%	30%	Yes
USA	Mid PPA	\$107	Low	3000	20.20%	21%	30%	Yes
USA	Mid PPA	\$107	Base	3600	17.60%	21%	30%	Yes
USA	Mid PPA	\$107	High	4000	16.30%	21%	30%	Yes
USA	High PPA	\$115	Low	3000	21.20%	21%	30%	Yes
USA	High PPA	\$115	Base	3600	18.60%	21%	30%	Yes
USA	High PPA	\$115	High	4000	17.10%	21%	30%	Yes
Japan	Low PPA	\$135	Low	3000	20.70%	30%	-	Yes
Japan	Low PPA	\$135	Base	3600	18.00%	30%	-	Yes
Japan	Low PPA	\$135	High	4000	16.60%	30%	-	Yes
Japan	Mid PPA	\$145	Low	3000	21.80%	30%	-	Yes
Japan	Mid PPA	\$145	Base	3600	19.00%	30%	-	Yes
Japan	Mid PPA	\$145	High	4000	17.60%	30%	-	Yes
Japan	High PPA	\$155	Low	3000	22.80%	30%	-	Yes
Japan	High PPA	\$155	Base	3600	20.00%	30%	-	Yes
Japan	High PPA	\$155	High	4000	18.50%	30%	-	Yes
S. Korea	Low PPA	\$105	Low	3000	17.70%	25%	-	Yes
S. Korea	Low PPA	\$105	Base	3600	15.30%	25%	-	Yes
S. Korea	Low PPA	\$105	High	4000	14.00%	25%	-	Yes
S. Korea	Mid PPA	\$115	Low	3000	18.90%	25%	-	Yes
S. Korea	Mid PPA	\$115	Base	3600	16.40%	25%	-	Yes
S. Korea	Mid PPA	\$115	High	4000	15.10%	25%	-	Yes
S. Korea	High PPA	\$125	Low	3000	20.20%	25%	-	Yes
S. Korea	High PPA	\$125	Base	3600	17.60%	25%	-	Yes
S. Korea	High PPA	\$125	High	4000	16.20%	25%	-	Yes
Europe	Low PPA	\$105	Low	3000	17.70%	25%	-	Yes
Europe	Low PPA	\$105	Base	3600	15.30%	25%	-	Yes

Country	PPA Scenario	PPA Price 2026	Capex Scenario	Capex (\$/kW)	IRR (%)	Tax Rate	ITC	Inflation Indexed
Europe	Low PPA	\$105	High	4000	14.00%	25%	-	Yes
Europe	Mid PPA	\$132	Low	3000	21.10%	25%	-	Yes
Europe	Mid PPA	\$132	Base	3600	18.40%	25%	-	Yes
Europe	Mid PPA	\$132	High	4000	16.90%	25%	-	Yes
Europe	High PPA	\$160	Low	3000	24.20%	25%	-	Yes
Europe	High PPA	\$160	Base	3600	21.20%	25%	-	Yes
Europe	High PPA	\$160	High	4000	19.60%	25%	-	Yes
Taiwan	Low PPA	\$120	Low	3000	20.20%	20%	-	Yes
Taiwan	Low PPA	\$120	Base	3600	17.50%	20%	-	Yes
Taiwan	Low PPA	\$120	High	4000	16.10%	20%	-	Yes
Taiwan	Mid PPA	\$150	Low	3000	23.80%	20%	-	Yes
Taiwan	Mid PPA	\$150	Base	3600	20.80%	20%	-	Yes
Taiwan	Mid PPA	\$150	High	4000	19.20%	20%	-	Yes
Taiwan	High PPA	\$180	Low	3000	27.10%	20%	-	Yes
Taiwan	High PPA	\$180	Base	3600	23.80%	20%	-	Yes
Taiwan	High PPA	\$180	High	4000	22.00%	20%	-	Yes





## Appendix C – The Size of the Prize: Total Achievable Potential by Continent (GeoMap)

**The GeoMap dataset, accessible via Project Innerspace’s platform is the most granular publicly available tool for translating resource potential into investment-grade portfolio screens. It should be the starting point for any oil major’s geothermal prioritization exercise. Several observations from GeoMap (Table 4) are strategic for an oil major entering the geothermal market at scale:**

- Africa (15,904 GW near-term) is the largest continental resource, concentrated in the East African Rift System. Kenya’s KenGen (~985 MW installed, ~10 GW near-term potential) provides the proof-of-concept and the infrastructure base. Microsoft and G42’s announced 1 GW geothermal-powered data centre campus in Kenya signals that hyperscaler appetite is tracking the resource. For an oil major with existing acreage, partnerships, and drilling infrastructure across sub-Saharan Africa, this represents a first-mover window of material size.
- North America (10,827 GW) is the most commercially mature market, with established EGS startups (Fervo, Sage, XGS), proven technology transfer from oil and gas, and the world’s highest concentration of creditworthy hyperscaler offtakers. The US Western states and Texas ERCOT corridor represent Phase 1 priority development corridors where the PPA market is already functioning at \$100–115/MWh.
- Asia (11,351 GW) combines the world’s fastest-growing data centre markets (Indonesia, Japan, Singapore, South Korea, Taiwan) with substantial conventional geothermal resources on the Ring of Fire and a large future EGS potential (78,631 GW long-run). Indonesia alone has an estimated 24 GW of developable geothermal resource, of which less than 2.4 GW has been developed – an order of magnitude underdeveloped relative to resource size. PPA prices across this region (\$105–180/MWh) are structurally among the highest globally.
- Middle East (4,227 GW) is currently undeveloped but presents a distinctive opportunity: rapidly growing data centre hubs in Saudi Arabia, UAE, and Oman sit above substantial EGS potential. For oil majors with embedded subsurface knowledge, regulatory relationships, and operational infrastructure across the region, this is an optionality position worth holding – particularly as EGS costs decline through the 2030s.
- Europe (2,779 GW) is smaller in resource terms but commands the highest power prices outside Asia (\$105–160/MWh), driven by structural grid constraints and post-Ukraine energy security mandates. The Pannonian Basin (Hungary, Austria, Romania), Upper Rhine Graben (Germany, France), and deep geothermal programmes in the UK and the Netherlands represent near-term development opportunities, while Iceland offers a unique position as an ultra-low-cost geothermal jurisdiction with existing export infrastructure ambitions.



## Appendix D – The Future of Geothermal in Texas

### Key Findings Relevant to the O&G Investment Case

- Oil and gas technology transfer is the critical accelerant. Nearly 70% of oil and gas entities surveyed for the report stated there is no geothermal technical challenge that the O&G industry cannot solve. Almost 80% reported having a geothermal strategy in place or in development at the time of the survey. The report predicted – correctly, as subsequent events have confirmed – that O&G technology transfer would produce “breakthrough impact” on geothermal cost and performance, analogous to the shale revolution’s impact on oil production economics.
- The resource in Texas alone is enormous, and hotter than previously estimated. Geothermal resources are viable for electricity production across much of Texas at approximately 6.5 kilometers depth – a depth typical in parts of the oil and gas industry. Updated thermal modelling indicated the Texas subsurface is likely 15% hotter than prior estimates, materially improving project economics and technical feasibility.
- Geothermal is firm, always-on baseload – the complement to intermittent renewables. The report explicitly positioned geothermal in the same grid role as coal, nuclear, and natural gas: always-on, 24/7 capacity factor, no storage requirement. This characteristic was identified as uniquely valuable in the context of Texas’s ERCOT grid, which experienced catastrophic failure during Winter Storm Uri in 2021 precisely because of its dependence on weather-sensitive generation – a failure that subsequently drove near-unanimous legislative support for geothermal in the 2023 Texas session.
- The geothermal opportunity is global, not just Texan. The report noted that the enabling technology developed in Texas – EGS, closed-loop AGS, directional drilling into hot basement rock – is deployable anywhere in the world where sufficient subsurface heat exists. This global transferability is what converts a regional opportunity into a thesis for capital allocation at oil-major scale.
- The Texas report was the first comprehensive study to make explicit that the shale boom’s intellectual offspring – horizontal drilling, multi-stage fracturing, factory-model well manufacturing – could be pointed at an energy resource whose scale dwarfs hydrocarbons. It set in motion the regulatory changes, industry engagement, and capital formation that have since produced Fervo’s operating projects, Sage’s ERCOT deployment, and Shell Energy’s first EGS PPA. It is, in a meaningful sense, where the oil and gas industry’s geothermal vision began.



## Appendix E - The Geothermal Energy from Oil and Gas Demonstrated Engineering (GEODE) Roadmaps

The Geothermal Energy from Oil and Gas Demonstrated Engineering (GEODE) Consortium, led by Project InnerSpace and the Society of Petroleum Engineers, and supported by the United States Department of Energy (DOE), was established to accelerate the migration of oil and gas capabilities into the geothermal sector. Bringing together experts from more than 130 organizations across both industries, GEODE used structured roadmapping and cross-sector collaboration to evaluate pathways and build alignment on scaling geothermal as a foundational element of the U.S. energy system, covering four areas of action.

**The Technology Transfer Roadmap** consolidates insights from five dedicated task forces, outlining how geothermal can effectively leverage oil and gas technologies and expertise. It identifies key bottlenecks to industry growth, highlights the most promising areas for knowledge transfer, and defines actionable measures to de-risk projects, accelerate deployment, and lower costs across the full project lifecycle, from subsurface characterization modeling to production engineering and water management, covering gaps in drilling rigs and tools, completion and well design and stimulation.

**The Demonstration and Deployment Roadmap** examines critical data gaps that constrain the identification of geothermal resources in the United States and evaluates how existing oil and gas infrastructure can be

repurposed for pilot and demonstration projects to fast-track development, ideally with industry-led consortia to provide performance data that consolidates the geothermal business case.

**The Barriers to Expansion Roadmap** integrates analysis across four core domains—offtaker demand, project finance, policy and permitting, and stakeholder awareness—to clarify the primary constraints on industry growth. Subject matter experts assess structural challenges such as limited investor confidence in performance and a lack of standardized contracting and valuation frameworks and regulatory challenges such as protracted permitting timelines and heat ownership gaps, while proposing targeted strategies to address these barriers and enable scale.

**The Workforce Adoption and Innovation Roadmap** focuses on building a resilient geothermal workforce through three pillars: education and training, apprenticeships and labor alignment, and innovation and entrepreneurship. It evaluates how to mobilize talent from diverse entry points—including academia, skilled trades, and oil and gas—while strengthening technical career pathways and accelerating the translation of research into commercially viable ventures.

These roadmaps are fully complete, and currently awaiting DOE approval to publish.

## Appendix F - Risk Assessment

Risk	Severity	Mitigant
<b>Subsurface performance:</b> EGS reservoir productivity at commercial scale still being validated	Moderate	Portfolio approach across multiple geologies; phased investment gated to performance milestones; Fervo Cape Station (2026) is the near-term validation event
<b>PPA price compression:</b> Increased supply or demand moderation reduces the firm clean premium	Moderate, post-2030	Early-mover advantage locks in long-term PPAs at current premiums; geothermal LCOE continues falling, protecting margins; even at \$80/MWh, returns are utility-grade
<b>Drilling cost stagnation:</b> Learning curve flattens before reaching \$3,000/kW	Low-to-moderate	Your drilling optimisation capability is the primary lever. Phase 1 targets \$4,000-5,000/kW, delivering 10-18% IRRs—already commercially viable. Phase 2 cost reduction to \$3,000-4,000/kW drives IRRs to 14-27%, but even if costs plateau at \$4,000/kW, Phase 2 projects in premium markets (Europe, Taiwan, Japan) still deliver 14-19% returns. History of shale industrialization demonstrates sustained cost reduction through factory execution.
<b>AI demand moderation:</b> Efficiency gains (e.g., model optimisation) slow power demand growth	Possible, but even conservative scenarios show substantial growth	Geothermal's contracted revenue and zero fuel cost provide downside protection vs. commodity-exposed alternatives. The Hyperscaler demand dynamic (Section 1.3) suggests demand is more likely to be supply-constrained than demand-constrained
<b>Regulatory/permitting delays</b>	Moderate in US	Behind-the-meter deployment on private land avoids many federal hurdles; geothermal has bipartisan support and is included in the current administration's energy emergency executive order
<b>Induced seismicity:</b> Public opposition to hydraulic stimulation	Low-to-moderate	EGS stimulation is substantially smaller scale than shale fracking; robust monitoring (DAS/DTS fiber optics), traffic-light protocols well-established
<b>Capital commitment scale:</b> \$12-25B initial commitment is a major allocation decision	Moderate	Phased deployment with clear stage-gates. Phase 1 spending is comparable to a single deepwater FPSO cycle. Returns and market validation at each phase gate inform subsequent commitments. The risk of not acting – ceding a contracted-revenue market to competitors – must be weighed against the risk of commitment
<b>Cannibalization of upstream workforce</b>	Low	Phased deployment; geothermal growth absorbs workforce that might otherwise face redeployment as mature basins decline

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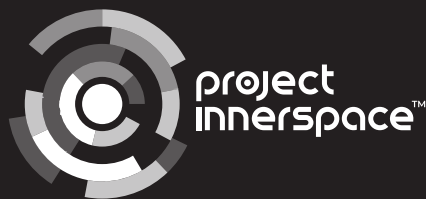
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**“The question is whether the oil majors will watch others capture a market that is custom built for the legacy strengths of the industry.”**



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