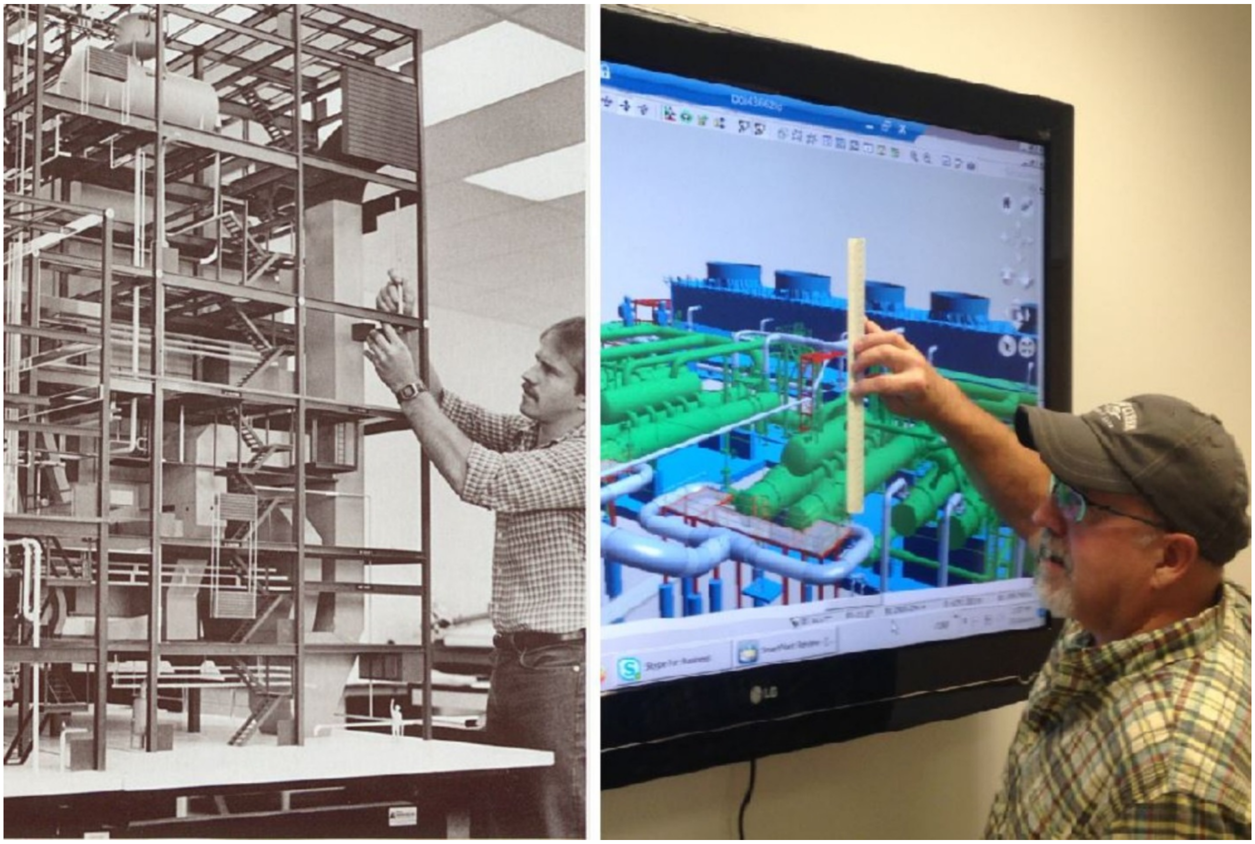
Geothermal Insights I: An industry retrospective over the past two decades



The inexorable march of time (Photos: Warren Cordingly)

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By William Harvey

This is the first of a three-part series discussing the trajectory of the geothermal industry: past, present and future. It is written from my perspective working for POWER Engineers, and draws on our company's history of engagements in the surface facility aspects of geothermal projects. This experience spans conceptual design and feasibility studies, detailed flash and binary plant design, monitoring of projects as an owner's engineer, and performing independent engineering for lenders. Since we at POWER are simple engineers and not geoscientists, profound insights on advances in reservoir exploration and utilization are best left to others. Although we primarily focus on surface aspects here, it is inevitable that we will have to talk a bit about reservoirs and drilling to draw a fuller portrait.

In this first installment, let's consider the question: how have things changed from 1997 to 2017 - what major trends are evident? The second installment will address the life of people engaged in this industry. What are geothermal projects like? Why do we enjoy this work? And the third installment will be speculation about the future of the industry. How does geothermal stack up against other conventional or renewable power generation options? How can our industry continue to contribute and be competitive in the coming years?

First, a retrospective.

Geothermal hot tub time machine - 1997

Climb into the wormhole of your choice, and emerge in 1997. What do we see around the landscape of the geothermal industry?

A wave of ~55 MW flash (harnessing separated steam from relatively high temperature resources) or dry steam plants had been installed in the late 1980s and 1990s across Indonesia, the Philippines, Costa Rica and the U.S. primarily. These projects served as templates for many developments at similar large, energetic resources. The tall powerhouses for their bottom-exhaust steam turbines offered an efficient design with a modest footprint.

Miravalles I/II: poder a Costa Rica desde 1994.

Binary plants (which use lower temperature geothermal fluid in a heat exchanger to vaporize a lighter working fluid, which is used in a closed Rankine cycle) had appeared on the scene. However, these projects were generally small, less than 5 MW per turbine for the most part. The number of suppliers was relatively limited. For the Heber SIGC project in California, shown below, twelve 2.75 MW turbines were combined for a 33 MW project, one of the larger binary installations of that time.

Heber SIGC under construction, back in the Polaroid days.

For us engineers, designs were often performed in 2D, but more complex 3D plant model environments were also starting to be used. Lego lovers got to construct real plant models, although that practice was fading out. Fax machines were still a staple. Hardcopy drawings and documents circled the globe for review via expensive and fast-for-the-time-but-still-slow delivery services.

Back to the future: 2017

The geothermal industry has come a long way, though it may seem like the basic steam and binary plant features look similar, at first glance. However, the relentless drives of technology and economics have spawned a host of improvements.

Plant configurations abound. Bottom, top and axial exhaust steam turbines may each offer specific performance or cost advantages for a project. Innovation in binary turbines means developers can choose from axial flow, radial inflow and radial outflow options and ever increasing sizes. More efficient direct contact condensers and surface condensers that can harvest thermal energy for other uses such as district heating can each have a role. The traditional massive crossflow cooling tower has in many places given way to more efficient, lower profile counter-flow designs. Air- and water-cooled combined cycles—mixing flash and binary technology—are seeing wider application, where specialized project conditions warrant.

Want to know more? Check out [Advances in Turbine and Direct Contact Condenser Configurations, and Balance of Plant Considerations](#).

One irresistible force, where the resource size permits, is towards economies of scale, and this has influenced both flash and binary plant development choices. The 121 MW Darajat dry steam plant in Indonesia, the 140 MW Nga Awa Purua triple flash plant in New Zealand, and the 139 MW Olkaria III binary complex in Kenya are some examples. Plus, 100+ MW steam turbines and 15+ MW binary turbines are now available to make possible larger and more economical development steps.

The number of binary suppliers has increased as the industry has expanded, offering developers more choices for working fluids and surface facility configurations and keeping costs competitive. Binary suppliers can also offer these solutions to other industries such as biomass and waste heat recovery, and realize their own economies of scale. “Modular” solutions, which can reduce field assembly labor and time as components are shipped as packaged units, are more available, though still confined to the smaller projects.

Small “wellhead” flash plants, up to around 5 MW, also semi-modularized, are now increasing their presence. These can be more swiftly constructed and commissioned and generate revenue for some time prior to larger plants being placed in service. The wellhead units can then be moved to a new development to continue their service as vanguards.

On the engineering side, the pace of both design and project execution have been accelerated significantly. Better geoscience analysis and predictions means projects can start design and procurement of major equipment at an intermediate stage in drilling, rather than waiting for more complete wellfield development. The Internet and software tools such as database-driven 3D models make communications across continents and companies simpler, and one could say engineering has moved to a “24-hour cycle,” much like cable news. Swift electronic exchange of documents for review between owners, engineers, vendors and contractors has taken large chunks out of the schedule; time spent previously waiting for hardcopy documents to get shipped and potentially lost.

Some countries have seen incredible strides in installed capacity over the past two decades. Kenya and Turkey are two examples, as illustrated in the paper linked below. In the case of Turkey especially, encouraging feed-in tariffs (FIT) have accelerated not only project development, but also spurred in-country manufacturing of components such as binary turbines, thanks to targeted industrial incentives.

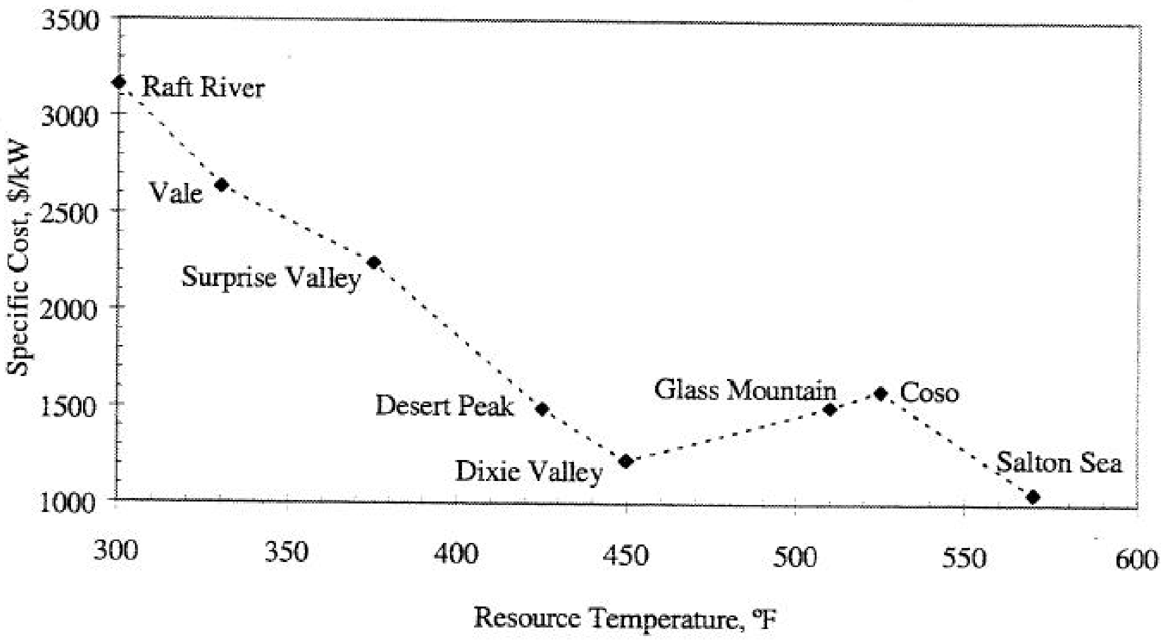
Want to know more? Check out Harvesting Best Practices – a Comparison of Kenyan and Turkish Geothermal Project Aspects.

Capital costs and LCOE: how far (or not far) we have come

Improvements in resource exploration and drilling techniques, plant equipment and materials, project execution and structure strategies—how have they translated to project costs?

There is a convenient means of comparison for capital costs and levelized costs of electricity (LCOE) over the past two decades. The Electric Power Research Institute (EPRI) and the esteemed firm of CE Holt developed in 1996 the Next Generation Geothermal Power Plants report, which examined the estimated capital and operating costs for various plants. These project scenarios ranged from higher temperature resources in the fields of California such as the Salton Sea and Geysers, to modest temperature resources in areas such as Nevada and Utah, and examined both flash and binary technologies. A nominal plant size of 50 MW (net) was used for comparisons.

The figure below shows the 1996 estimated specific capital costs for geothermal projects (including wellfield and power plant) as a function of resource temperature, with the lower temperature binary project at Raft River estimated as around 3,200 $/kW (net), and the hottest resource flash plant at the Salton Sea estimated as around 1,000 $/kW.



Project specific capital costs from the 1996 EPRI report.

The corresponding LCOEs for these projects from the 1996 EPRI report range from around 70 $/MWh at the lower temperature resources such as Vale, to around 60 $/MWh at a higher temperature resource such as Coso. While LCOE depends also on a wide set of economic (financing) assumptions used, let's move on to a comparison with more recent conditions.

Although it is a few years old, ESMAP's 2012 *Geothermal Handbook: Planning and Financing Power Generation* is such a great reference, with a wealth of knowledge and data that in my opinion is a good match to what I see in the industry, I feel compelled to use it for this comparison. Given the wide range of aspects that can vary between countries and fields such as drilling, labor and plant equipment costs, the ESMAP report presents for a typical 50 MW plant a "low estimate" around 2,800 $/kW, "medium estimate" around 3,900 $/kW, and a "high estimate" around 5,500 $/kW. Even inflation-adjusted (perhaps +50-60%) from 1996 to 2012, these specific capital costs are a bit higher than the values in the older EPRI report. This may in part been due to the most easily exploitable resources being the "low hanging fruit" that were generally the first to be harnessed. Very roughly, around 45-50% of the cost of a geothermal project is the power plant, perhaps 40% or so is drilling the wells, and another 10-15% or so for other aspects like the pipelines connecting the wells to the plant or the transmission lines. Project economics can thus be very site-sensitive to the drilling costs.

What's interesting is that the indicative LCOEs in the 2012 ESMAP report are comparable or lower than those in the 1996 EPRI report. Depending on the country and technology type, current power generation costs from new geothermal projects can range from what seems like very aggressive pricing of around 50 $/MWh for the large, high temperature resources in locations like Indonesia and Iceland. For smaller projects at more modestly energetic resources such as in the U.S. and Turkey, we see projects that are feasible with power values around 80-105 $/MWh.

Improvements in plant efficiencies, operations and maintenance, speed of project execution and other factors apparently have helped maintain or reduce LCOE over the past two decades despite (or perhaps because of) some modest inflation in capital costs. Depending on the location, geothermal can currently approach or be less than the LCOE of fossil-fired baseload generation alternatives, showing that this has evolved into a competitive renewables alternative. (I will talk about comparisons with intermittent renewables such as solar or wind later.)

In summary

Twenty years of diligent effort by the worldwide geothermal industry has brought the global geothermal installed plant capacity from around 7 GW in 1996 (Bertani 2007) to over 13.5 GW in 2017 (REN21 2017). Through improvements in technology and project execution, LCOEs have remained relatively constant or even dropped in real terms. Improvements in geoscience and drilling success, a wealth of efficient cycle types for a variety of sizes and applications, and competitive supplier options, make this a good time to be a developer…so long as there is a reasonable power purchase agreement or access to decent FITs.

I hope this provides a short but useful overview of our perspective on what changes the geothermal industry has experienced in the past several decades. In the second installment in this series, I will talk about life in the present: a view "from the hotwell pit" of what makes geothermal an interesting and rewarding field. In the third installment, I will then try to peer into the future at what the coming years may bring.

About the Author

William Harvey, P.E. is a project engineer and a Ph.D. in Mechanical Engineering specializing in renewable energy projects, principally geothermal. His background includes design, commissioning and operating experience in mechanical, nuclear, chemical, and electrical power plant aspects. With POWER Engineers, he has served in all project phases for flash and binary geothermal plants, including projects commissioned in the Americas, Africa, Turkey and Asia. His roles span detailed design, owner's engineering and independent engineering. Dr. Harvey has delivered training for industrial clients and organizations such as the Electric Power Research Institute, the Geothermal Resources Council, Kenya Electricity Generating Company, Costa Rica's Instituto Costarricense de Electricidad, the Iceland School of Energy at Reykjavik University, and the International Finance Corporation, among many others. He writes and lectures extensively on geothermal and renewable energy topics. He tries to maintain a personal blog on semi-random engineering and renewable energy career topics at www.badgercrossroads.com. He is a contributing author for the textbook Geothermal Power Generation: Developments and Innovation (2016).

Please note that the opinions expressed in these posts are my own and not necessarily those of my employer.

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