

Geothermal Costs of Capital: Relating Market Valuation to Project Risk and Technology

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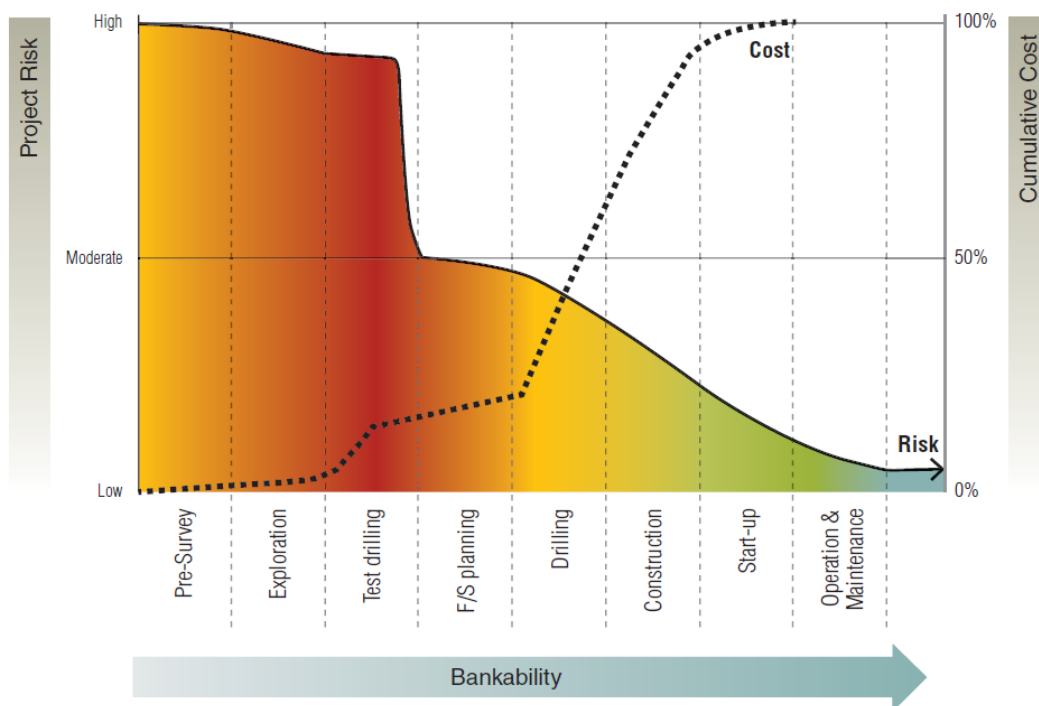
ABSTRACT

Access to financing has frequently been noted as a barrier to geothermal project development, due to the high perceived risk during exploration and drilling. However, little information has been made available to ascertain the costs of capital at stages of geothermal project development, and the sensitivity of these financing changes to the overall economics of a project. While financing is in large part related to the creditworthiness of the counterparty, this study seeks to uncover relationships between resource-associated risks and variations in cost of capital with project advancement. This study primarily focuses on summarizing the current “business as usual” costs of capital and proposes scenarios for future financial projections to support modeling of energy technology economic competitiveness in the U.S. Department of Energy’s *GeoVision* Study. Ongoing work will refine a model relating improved market costs of capital presented herein to assumed improvements in project risk.

1. Introduction

Structuring project finance for geothermal projects strikes an important balance in compensating the investor for both the opportunity cost of providing capital and the risk in succeeding with resource development. In geothermal projects, the perceived risk of the project drops significantly as production drilling proceeds in line with the expectation of higher certainty about the project’s realization, based largely on progressive de-risking of the resource uncertainties (Figure 1). As a result, the type of financing available (e.g. equity or debt) and the hurdle rates necessary to invest are heavily tied to the stage of project feasibility. Previous studies of these rates have primarily been a consensus or range from market participants (Salmon et al., 2011).

Geothermal Project Risk and Cumulative Investment Cost



Handbook on Planning and Financing Geothermal Power Generation

Figure 1: Diagram of cumulative investment costs and geothermal project risk over time (ESMAP, 2012). The test drilling stages of a project present the most significant barrier to geothermal development as the developer is typically confronted with a combination of high risk and high capital expenditures for confirmation activities.

In theory investors make rational capital budgeting decisions, such as investing in a geothermal project, by considering financial valuation methods that incorporate this uncertainty over the lifetime of the project. Furthermore, geothermal project uncertainty is well known to vary based on the type of project and project technology; for example, an expansion hydrothermal project has a far higher probability of development completion than a greenfield project. Since the assumptions entrained in these financial models include both the project stage and risk at a given period, changes to these factors significantly influence the perceived value of the project. While numerous studies have evaluated the mechanisms and risks associated with geothermal financing (e.g., J.M. Energy Consultants, Inc., 1981; Worchester and Boggs, 1982; Tansev, 1987; Raviv et al., 2006; McIlveen, 2011; ESMAP, 2012; Dumas and Angelino, 2015), these evaluations have typically reviewed or identified these sources of valuation variability in only cursory detail.

This work has been undertaken as part of the U.S. Department of Energy's wider *GeoVision* study: a multi-year research collaboration amongst national laboratories, visionary experts from industry, and academia aimed at identifying scenarios for growth of the U.S. geothermal industry resulting from R&D advancements that could generate cost reduction and improved performance across the full range of geothermal resources and technologies. The goal of the *GeoVision* study

is to explore the potential contribution of geothermal energy to the U.S. economy and energy portfolio via expanded utilization of geothermal resources.

The first section of this paper reviews financial concepts underlying this analysis, such as the theory of optimal capital structure and the most common forms of risk adjustments to valuation estimates. The second section provides examples of these concepts applied to geothermal cases, including case studies of recently financed geothermal projects as well as the development of future financing cases for the industry structured for use in the *GeoVision* study. The third portion of this work discusses the basis for these financial rate fluctuations by positing a relationship of how project success rates effect change to valuation.

Two caveats are necessary in the reading and use of this paper:

- 1) Project financing, including that of mining and geothermal projects, requires that costs of capital are adjusted to the combined amount of debt and equity sought by the funded project. This serves as a reminder that figures compiled in the remainder of this paper are only relevant for the proportion of debt and equity listed below.
- 2) Costs of capital, if adequately priced to capture risk, should in theory be reflective of the investor's minimum required rate of return. The following discussion of costs of capital are not reflective of the expected return that he or she may receive from making the investment.

This discussion is not in any way intended to provide the sole basis for the evaluation of a given geothermal project's bankability nor does it in any way purport to contain all the information that may be required to evaluate a project's financial capacity. Each project must be evaluated independently and with its own independent verification. This discussion does not in any way represent investment advice.

2. Review of Financial Valuation Concepts

The type of capital used, and when it is deployed, are significant factors in an investor's ability to minimize the risk of the investment and generate sufficient financial returns. Similarly, the flexibility and availability of sufficient amounts of capital are critical for developers to continue the up-front expenditures required for exploration and infrastructure project development. Projects supported entirely by equity (whether a company's retained earnings or an external entity's bank account) require such investors to tie up large financial resources out of reach from other investment opportunities. The cost of equity is the required rate of return given the opportunity cost and risk of allocating the funds. The cost of debt is the market rate paid by the specific firm to borrow. While the tax deductibility of interest expenses makes projects supported entirely by debt instruments theoretically attractive, pure debt investments are not feasible for very early stage resource-based exploration due to restrictive covenants on repayment amounts and timing of cash flows (e.g. debt service coverage ratios).

A firm's optimal capital structure, i.e., the mix of equity and debt carried, has been demonstrated by a wide body of financial literature to exist as a mixture of components: the balance of tax benefits and bankruptcy (i.e., Modigliani and Miller (1958)), the costs of issuing various securities, agency costs with different securities, and the costs associated with adverse selection (e.g., risky debt, dissected by Merton (1974)). While individual project finance is distinct from

capital budgeting and optimization for an entire firm, the concepts of optimal capital structures still largely apply for the project itself. For example, real options and modified contingent claims models (e.g., Brennan and Schwartz (1985); Mello and Parsons (1992)) have been used in mining projects to demonstrate how the effects of leverage introduce agency costs via changes in optimum operational strategies. Although mining economics are a fitting analogy for geothermal's process of mining for heat, given the debate underlying why debt is not always attractive, this initial overview will not attempt to dissect which of the above factors are most prominent in the capital structure for geothermal projects. Instead, this paper provides an overview of previous research on geothermal financing to highlight the importance of changes to capital structure over time.

In considering a firm's capital structure, an underlying assumption is that the project's inherent value (and the return on any initial investment) is being determined by value of the project's future free cash flow discounted over time. A discounted cash flow valuation can either assume a weighted average cost of capital (WACC) of the equity and debt costs as the discount rate for the entire project, or can adjust for the varying costs of debt over specific periods in the course of the project lifetime (i.e. adjusted present value, APV). WACC combines both investments in debt and equity in the following proportions:

$$\text{WACC} = r_D (1 - T_c) * (D / V) + r_E * (E / V)$$

where:

r_D is the pre-tax cost of debt,

r_E is the cost of equity,

T_c is the marginal corporate tax rate,

D is the dollar amount of debt,

E is the dollar amount of equity, and

V is the company's book value ($D + E$).

APV assumes the cost of equity is an appropriate discount rate for cash flows and the cost of debt is used separately to calculate interest expenses (and associated tax benefits). While WACC is an easy substitution as the discount rate, APV is preferred for highly leveraged or buyout valuations because of its flexibility to capture the benefits of borrowing at different stages in time.

To account for risk and uncertainty, particularly for resource-based investments such as mining and geothermal, the probabilities of success/failure at stages can be used to generate a higher rate to discount future cash flows or to generate an expected value of the cash flows received (i.e. $rNPV$). Without this level of information, comparable market transactions such as asset sales and purchases alternatively allow for insight into a project's perceived value. In these cases, risk adjustments present themselves as a discount off the book value of the assets (Damoradan (ND)). If even this level of information is not robust, projects within different stages of development can be treated as having a "risk premium" assigned to the discount rate.

3. Geothermal Costs of Capital

Any analysis of recent geothermal financing suffers from the paucity of information available for review from historical projects. Instead, most recent analysis of geothermal financing has focused on policy mechanisms to improve investment returns (e.g., Speer and Young (2016); ESMAP (2012)). The most thorough analysis of the costs of capital paid by investors at varying stages of geothermal project development was published in 2011, and as such describes US market conditions existing during the Great Recession of 2008 (Salmon et al., 2011). Due to the combination of the prolonged economic recovery and the recent downturn in the US energy market, this discussion assumes that the recent state of the financial market has remained comparatively unforgiving in comparison to capital obtained pre-2008. This work dissects Glacier Partner's 2009 financial model accompanying its report and reviews available financial information on public companies as a supplement to reach a consensus on U.S. market conditions as of 2016.

If future market conditions for geothermal projects improve for any number of reasons (whether due to investor risk tolerance, higher demand for geothermal power, or lower project capital requirements), financing rates too are likely to adjust. In concert with the Department of Energy's current *GeoVision* Study, this study outlines the potential for alternative capital structures and financing rates under future conditions (i.e. scenarios), using analogous operations in other industries (i.e. mining and oil and gas).

Since availability of project capital changes as a project progresses, and thus so does the project's capital structure, the following discussions are organized by major project stage (exploration, confirmation drilling/wellfield development, plant construction, and operation). For the purposes of discussing potential *GeoVision* Study scenarios and a "business as usual" (BAU) base case, this paper includes the components of WACCs and the assumed proportion of capital expenditures at each project stage. WACCs are used as discount rates within the Regional Energy Deployment System (ReEDS) modeling that provides market competition amongst capital and financing costs for all technologies serving the electric grid (Eurek et al., 2016).

3.1 Compilation of Published Costs of Capital for Geothermal Projects

During early stages of exploration, projects have only been able to receive equity financing, either in the form of balance sheet funding or private equity. Balance sheet financing, i.e. the use of internal funding such as retained earnings, has required a minimum hurdle rate of 12-13% (Glacier Partners, 2009; Salmon et al., 2011). Private equity or venture capital, if available, has required a cost of equity at minimum 30%, with 35% being preferred (Damoradan).

During drilling, mezzanine financing offers the ability to obtain between equity and debt as a bridge between commercial lending and private equity. Glacier Partners (2009) notes that historically commercial lenders would offer construction loans after 60% of the well field development, but this practice ceased during the Great Recession of 2008 and had not resumed at the time of publication. Costs of mezzanine equity are at minimum 25%, with 30% being preferred, while costs of mezzanine debt are approximately 12.5% above Libor, with 15% in total being preferred (Glacier Partners, 2009; Salmon et al., 2011).

Construction loans have commonly been as expensive as 6.5% above Libor (Glacier Partners 2009)), but were seen from 5.32% to 5.57% depending on whether a project had obtained a PPA (Salmon et al., 2011).

Ormat's acquisition of the Heber field serves as an example of the cost of refinancing of an operating geothermal project (Raviv et al., 2006). Ormat used 144A Senior Secured Notes underwritten by Lehman Brothers to obtain \$165 million in financing from institutional investors in 2005, with a 15year term. The financing process was assisted by having the bonds rated (BBB by Fitch), a long-term power purchase agreement in place, a proven resource with established well field performance, and an experienced developer. The resulting debt facility was priced at US Treasury + 170 basis points, equivalent to 6.21%, but Ormat also used a Treasury lock (a form of a fixed-for-floating swap) that created an effective coupon of 5.75%. This rate is on par with construction loan costs with a PPA (i.e. 5.3%) cited as representative during recent periods of tight liquidity (Salmon et al., (2011).

Using proportions of spending generalized from Glacier Partner's financial model and the Geothermal Electricity Technology Evaluation Model (GETEM) (Mines, 2016) for a typical hydrothermal project, the above literature can be summarized as either an external financing case (in which a developer is reliant on private equity and mezzanine financing) and an internal financing case (in which retained earnings, corporate loans, and mezzanine loans are available). Table 2 below outlines these combinations by generalized project phase.

Table 2. Summary of available literature on geothermal costs of capital, compiled into project WACCs using generalized proportions of capital expenditures by project phase.

Project Stage	External Financing				Internal Financing				% of Spending
	<i>Cost of Equity (%)</i>	<i>Cost of Debt (%)</i>	<i>E / (E + D)</i>	<i>D / (E + D)</i>	<i>Cost of Equity (%)</i>	<i>Cost of Debt (%)</i>	<i>E / (E + D)</i>	<i>D / (E + D)</i>	
<i>Exploration - Feasibility</i>	35%	n/a	100%	0%	13%	n/a	100%	0%	12%
<i>Drilling / Well Field Development</i>	30%	15%	40%	60%	12%	15%	40%	60%	58%
<i>Plant Construction & Start – up</i>	n/a	8%	0%	100%	n/a	5.3%	0%	100%	30%
WACC	19.4%				14.0%				

3.2 Current Market Valuation

To supplement published literature, this work researched current costs of capital calculated for public geothermal companies operating in the U.S. (Table 1):

Table 3: Summary of Bloomberg L.P. terminal data service for selected public geothermal operators
(WACC and BETA functions, as of October 2016)

<i>Company</i>	<i>Cost of Equity (%)</i>	<i>WACC (%)</i>
US Geothermal	3.09	3.6
Ormat	8.86	7.1
Calpine	9.97	Not Available
Polaris	10.51	7.1

Since these public companies are well established and both operate and explore for multiple new projects, the above current WACCs are likely to be an aggregate of both operational and exploration costs of capital. To delineate the differences in capital structure over specific periods of project progress, this work investigated the historical changes in costs of capital for the period of time over which it was publicly known that a new project was being developed for U.S. Geothermal (2007-2014, the development of Neal Hot Springs, Oregon). Table 4 matches the cost of equity and debt to the periods of project progress represented in the graph of U.S. Geothermal's WACC in Figure 2 below.

Table 4: Summary of Bloomberg L.P. terminal data on the costs of capital and capital structure for U.S. Geothermal (HTM:US) by generalized project stage (WACC and BETA functions, as of October 2016). Note that the cost of debt (r_D) is provided on an after-tax basis.

<i>Project Stage</i>	<i>Cost of Equity (%)</i>	<i>Cost of Debt (%)</i>	<i>Equity / (E + D)</i>	<i>Debt / (E + D)</i>
Pre-feasibility	12.9%	n/a	100%	0%
Initial well	18.2%	4.0%	99.9%	0.1%
Well Field - start	10.5%	4.0%	75%	25%
Well Field - end	9.8%	2.6%	52%	48%
Construction/ Operation	6.0%	3.0%	25%	75%
Current	9.2%	3.0%	33%	67%

As seen in Figure 2, the increase in U.S. Geothermal's WACC up to March 2009 corresponds to public announcements in their SEC filings (10-Ks) of their beginning exploratory drilling. The WACC then decreases through the well field development, to the announcement of well field development activities completing in March 2010. The plant came into operation in 2013, visible in the small variability of the WACC after March 2013.

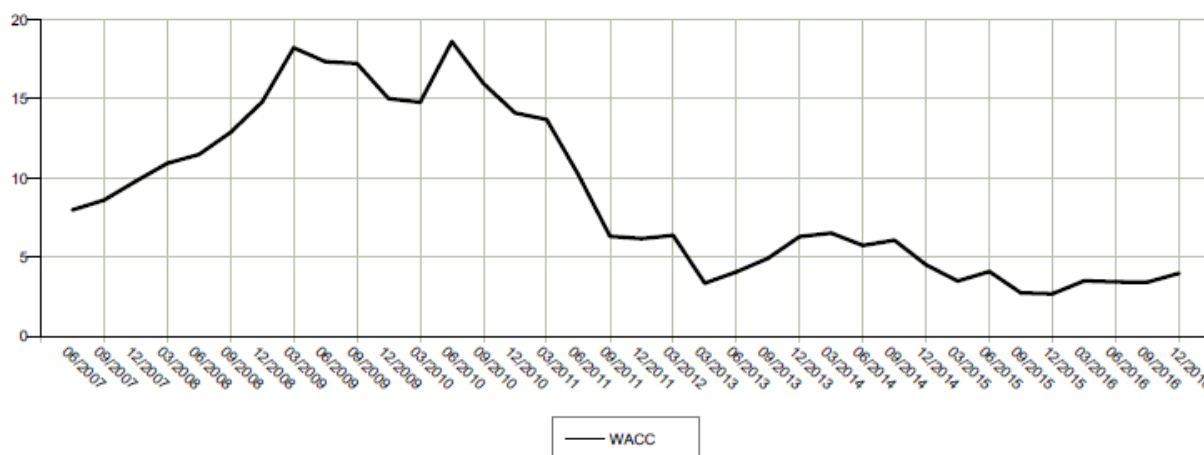


Figure 2: Historical WACC for U.S. Geothermal (Bloomberg LP as of December 2016)

3.3 Financing for Recent Geothermal Development Projects

To demonstrate the combination of financing that have been recently used in geothermal project development, we briefly review the funding sources that were employed by three companies for three new geothermal fields: Energy Source’s Hudson Ranch geothermal project in the Salton Sea, Ormat’s McGinness Hills geothermal project in Nevada, and U.S. Geothermal’s Neal Hot Springs project in Oregon. While U.S. government assistance is not universally or consistently available to new projects (other than through tax credits, accelerated depreciation and depletion allowances), each of these cases was positively impacted by government programs— either from prior research drilling (Hudson Ranch) or loan guarantees (McGinness Hills and Neal Hot Springs).

3.3.1 Hudson Ranch

The 49.0 MW Hudson Ranch project (Grogan, 2011) in the Salton Sea is located very near the site of research well State 2-14 that was jointly funded by the US Department of Energy, the US Geological Survey, and the National Science Foundation. This 10,564 feet deep well encountered a maximum temperature of 355°C and identified the presence of viable geothermal resources (Elders and Sass, 1988), which lowered the risk of conducting exploration activities in this area.

After securing the leases, the Energy Source consortium obtained initial financing and proceeded with exploration and confirmation drilling activities (Project Finance Magazine, 2011; Salmon et al., 2011). Equity investment in the project was \$101.1 million, of which \$90 million was contributed by GeoGlobal, Energy LLC (now Mercury Energy). The first two wells that were drilled were financed by a \$15 million loan from Glitnir Bank (now Islandsbanki) – the positive results from these wells, which were assessed to confirm a minimum resource of 30 MW, supported the bank debt component of the financing. Per comments by the lender, the combination of the well results (i.e. approximately 75% of the project’s capacity behind well head), the PPA, and the underlying GGE equity provided the assurance necessary to issue the debt. Energy Source was able to negotiate a 30-year power purchase agreement with Salt River

Project, a major utility for the Phoenix, Arizona region. Energy Source used a managed EPC contract, whereby investors assumed various risks to lower overall costs. An eight-member bank syndicate raised debt financing for the project, and included refinancing the original \$15 million resource confirmation loan. The total project cost plus contingency is \$401.3 million, and was financed in two tranches. The debt is a \$300.2 million mini-term priced at about 325bp over Libor, and consists of a \$204.9 million tranche A 2 year-construction/5-year term loan and a \$95.3 million tranche B ITC cash grant bridge loan (2-year construction + 120 days). Tranche A was sized to ensure a healthy (1.5) debt service coverage ratio over an 18-year amortization, assuming \$50 million of contingency. The project was subsequently refinanced with a senior loan (~\$313 million), the cash grant (~\$102 million) and tax equity (~\$99 million).

3.3.2 McGinness Hills

Mineral exploration efforts in the McGinness Hills area by several companies encountered hot water, which led to Ormat obtaining a lease for this blind geothermal prospect in 2007. Exploration drilling in 2009 resulted in the discovery of the McGinness geothermal field (Nordquist and Delwiche, 2013). Successful confirmation drilling led to decision to proceed with first phase of development, a 30 MW binary cycle system.

Ormat decided to fund this and two other geothermal development projects (Jersey Valley and Tuscarora) using a 20-year loan for up to \$350 million with John Hancock Life Insurance Company, guaranteed by the U.S. Department of Energy's (DOE) Loan Guarantee program under Section 1705 of Title XVII of the Energy Policy Act of 2005, which was created to support the deployment of innovative clean energy technologies. The project also had the backing of a 20-year power purchase agreement with Nevada Power Company, a subsidiary of NV Energy (Ormat, 2011). The original phase of the project was completed in only five years (from lease to initial production). Subsequently, Ormat has expanded production at McGinness Hills to 90 MW in 2015.

3.3.3 Neal Hot Springs

The Neal Hot Springs area was originally explored by Chevron back in the 1970s, but efforts were abandoned due to the lower temperatures of this resource. With the advent of binary power plant technology, US Geothermal acquired the lease to this area in 2006, and drilled its first production well in 2008 near the site of the earlier Chevron discovery well. After confirmation of this resource, a 10-mile transmission line interconnection and a 25-year power purchase agreement was signed with Idaho Power (Sifford, 2014; Gilles, 2015). Three modular supercritical R134a organic Rankine cycle power plants with an air-cooled condenser were constructed at Neal Hot Springs, with a total net production of ~22 MW (DiPippo and Kitz, 2015; Gilles, 2015).

The project was financed using a 40% equity partner (Enbridge USA Inc.) together with a \$96.8 million loan guarantee under DOE's Title XVII loan guarantee program (US Geothermal, 2011; Gilles, 2015). This represents 75% of the \$130 million total project cost. The DOE loan financing has a fixed 2.6% APR, with a 22 year term.

3.4 Future Market Conditions

Forecasting future market valuation of projects and associated costs of capital is inherently uncertain. Nevertheless, for the purpose of investigating various potential future pathways within the *GeoVision* study this work considered market competitiveness of multiple technology options by assuming cases of future economic performance, including the ability to obtain financing. Since many other analogous resource-focused industries have begun incorporating advanced technologies that could be leveraged for the geothermal industry in some way, the following work outlines the potential for alternative capital structures and financing rates under a set of possible scenarios.

3.4.1 Technology Transfer

In this scenario, utility-scale plants (≥ 50 MW) continue to predominately be the project goal of developers, and geothermal providers are able to utilize many of the current best practices from other similar industries, such as oil and gas (and to a degree mining). Specifically, this scenario assumes that these best practices are able to be included within geothermal to a similar degree of success.

Data from the Bloomberg Terminal's WACC function was used to pull apart the costs of equity and debt incurred at different construction periods based on a review of current and historical data. Due to Chevron's expertise and significant business focus in advanced exploration for oil & gas, this case assumes Chevron's cost of equity can be representative for the improvements in costs of equity due to the transfer of business practices to exploration & drilling stages in geothermal projects. Since Chevron does not build or operate power plants, the average cost of equity incurred by US Geothermal and Ormat during periods in which they experienced plant startups is assumed to be more representative of costs of capital for such operations. Figure 2 above outlines history for U.S. Geothermal, and Figures 3 and 4 below provides historical trends in Chevron's and Ormat's WACC, respectively. The costs of capital for the combined scenario are summarized in Table 5. Comparing Tables 4 and 5 implies that technology transfers could reduce costs of equity for geothermal projects from 13-18% to 10-12%.

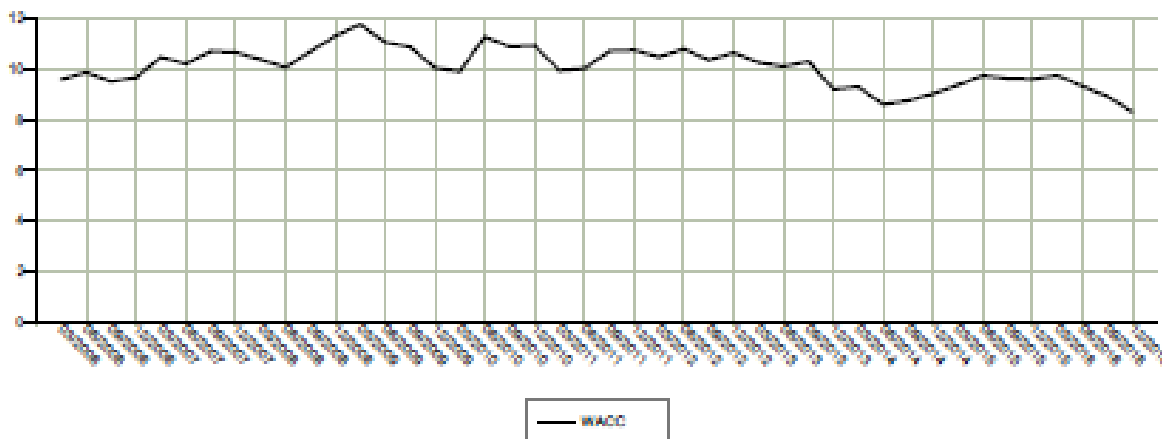


Figure 3: Summary of Bloomberg L.P. terminal data service (WACC function) for Chevron as of December 2016. At that time, Q3 2016 analysis indicated the company used 81% equity at 9.6% and 19% debt at an effective cost of 2.8%, for a WACC of 8.3%.

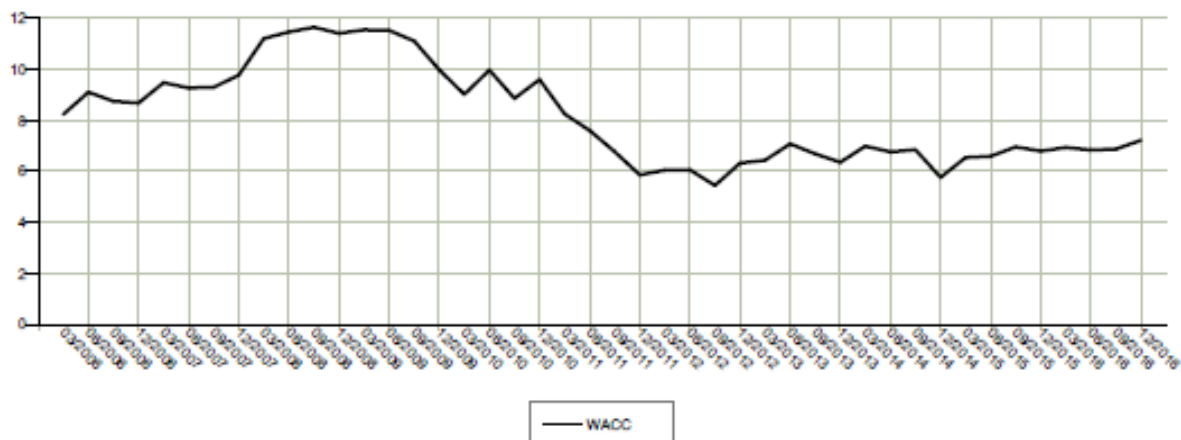


Figure 4: Summary of Bloomberg L.P. terminal data service (WACC function) for Ormat as of December 2016. At that time, Q3 2016 analysis indicated the company used 74.6% equity at 8.9% and 25.4% debt at an effective cost of 2.4%, for a WACC of 7.2%.

Table 5: Summary of assumed costs of capital for the Technology Transfer future scenario. Total WACC is the weighted average of the WACCs calculated at each project stage based on the project stage's proportion of total project expenses (% of Spending).

* Note that the cost of debt (r_D) is given on an after-tax basis.

<i>Project Stage</i>	<i>r_E</i>	<i>% Equity</i>	<i>r_D *</i>	<i>% Debt</i>	<i>WACC</i>	<i>% of Spending</i>
Exploration - Feasibility	10%	100%	4%	0%	9.60%	13%
Exploration - Drilling	10%	100%	4%	0%	9.60%	6%
Drilling	10%	15%	4%	85%	4.84%	44%
Field Gathering System	10%	0%	3%	100%	3.00%	8%
Plant Construction & Startup	6%	0%	3%	100%	3.00%	30%
TOTAL – Project WACC Weighted Average by Spending					5.01%	

3.4.2 High Technology Breakthroughs

In this scenario, utility-scale plants continue to predominately be the project goal of developers, and geothermal providers have advanced significant resource-focused technology breakthroughs from a confluence of current trends: the availability of big data to optimize drilling and exploration, and of advanced drilling techniques (such as microdrilling and multi-stage stimulation of horizontal wells) to increase confidence in exploration targeting and increase productivity of the projects chosen. Specifically, this scenario assumes that these technologies are all cost-effective and commercial by 2050.

Data from the Bloomberg Terminal's WACC function was used to extract the costs of equity and debt that occur at different construction periods based on a review of current and historical data.

This case assumes Exxon's cost of equity for exploration & drilling stages due to their current utilization of big data in exploration activities, and assumes that loans will be available at similar rates, if not lower (as of this last quarter, e.g. Exxon enjoys an effective long-term debt rate of 2.1%). Figure 5 provides historical trends in Exxon's WACC, and Table 6 compiles these assumptions into a financing scenario.

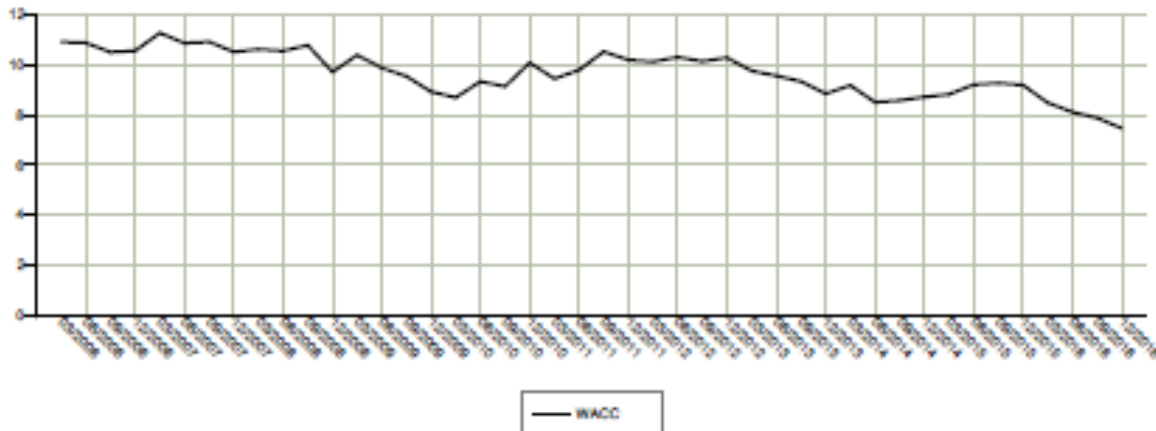


Figure 5: Summary of Bloomberg L.P. terminal data service (WACC function) for Exxon (as of December 2016). At that time, Q3 2016 analysis indicated the company used 88.7% equity at 8.2% and 11.3% debt at an effective cost of 2.1%, for a WACC of 7.6%.

Table 6: Summary of assumed costs of capital for the High Technology future scenario. Total WACC is the weighted average of the WACCs calculated at each project stage based on the project stage's proportion of total project expenses (% of Spending).

* Note that the cost of debt (r_D) is given on an after-tax basis.

<i>Project Stage</i>	r_E	% Equity	r_D *	% Debt	WACC	% of Spending
Exploration - Feasibility	8%	100%	4%	0%	8.20%	13%
Exploration - Drilling	8%	100%	4%	0%	8.20%	6%
Drilling	8%	15%	3%	85%	3.78%	44%
Field Gathering System	9%	0%	3%	100%	3.00%	8%
Plant Construction & Startup	6%	0%	3%	100%	3.00%	30%
TOTAL – Project WACC Weighted Average by Spending					4.29%	

3.4.3 Exploration De-Risking

In this scenario, the current business-as-usual approaches to project development are assumed to remain in place, but due diligence is more thoroughly vetted to meet exploration loan insurance and/or assistance programs (e.g., Schönwiesner-Bozkurt et al., 2005; Bloomquist et al., 2012). In these, such as the proposal by the IFC and World Bank, developers receive loans for exploration drilling but pay for only the wells which are successful; failures are absorbed through the funding mechanism.

Data from the Bloomberg Terminal's WACC function was used to extract the costs of equity and debt incurred at different construction periods based on a review of current and historical data. This case assumes US Geothermal's costs of capital and capital structure for drilling and plant development (see Table 4 and Figure 2 above), but assumes that the capital structure for exploration is largely determined by the probability of success: successful wells are required to pay back any loans (plus interest or fees), and unsuccessful projects are covered. Table 7 compiles these assumptions into a financing scenario.

Table 7: Summary of assumed costs of capital for the Exploration De-Risking future scenario. Total WACC is the weighted average of the WACCs calculated at each project stage based on the project stage's proportion of total project expenses (% of Spending).

*** Note that the cost of debt (r_D) is given on an after-tax basis.**

<i>Project Stage</i>	<i>r_E</i>	<i>% Equity</i>	<i>r_D *</i>	<i>% Debt</i>	<i>WACC</i>	<i>% of Spending</i>
Exploration - Feasibility	13%	33%	0%	67%	4.29%	13%
Exploration - Drilling	18%	33%	0%	67%	5.94%	6%
Drilling	10%	50%	4%	50%	6.80%	44%
Field Gathering System	10%	25%	3%	75%	4.75%	8%
Plant Construction & Startup	6%	0%	3%	100%	3.00%	30%
<i>TOTAL – Project WACC Weighted Average by Spending</i>					<i>5.14%</i>	

4. Inferred Risk Adjustments in Geothermal Financing

Using market-based rates for financing assumes that investors have implicitly valued the riskiness of the geothermal project, rather than adjusting explicitly for failure or uncertainty (i.e. r_{NPV}). Historically, probabilities of success for geothermal projects have been reviewed on a project progress basis (i.e. probability of moving forward in development (Wall and Dobson, 2016), and an economic basis (i.e. probability that the information available at a given stage leads to a project with a sufficient return (Cumming, 2016)).

Historical probabilities of project success should be broken further into the specific type of project: greenfield or brownfield. Using the same dataset investigated in Wall and Dobson (2016) and the same terminology of stages from exploration methods for drilling and for resource confirmation, this analysis was updated by first identifying projects as either greenfield or brownfield based on project information from the associated GEA reports (2013, 2014, 2015) or SNL Financial (2014, 2015). Table 8 shows two significant conclusions from this work: 1) that the majority of projects in development in this Nevada subset (where this dataset was taken) are greenfield, and 2) that the probability of success between a greenfield and brownfield project is a threefold increase, indicating significant improvements in probability of success for having available exploration research and test results at the beginning of a project.

Table 8: Breakdown of calculated probabilities of advancing (POA %) for major geothermal project stages: past the use of exploration methods (E^M), past exploration drilling (E^D), and past confirmation drilling (E^C). The probability of success is the product of the probability of advancing for each of the exploration stages.

Project Stage	All Projects		Greenfield		Expansion / Nearfield	
	# Projects	POA %	# Projects	POA %	# Projects	POA %
Total	137		112		13	
E^M Success	71	52%	52	46%	10	77%
E^D Success	35	49%	20	38%	9	69%
E^C Success	12	61%	7	61%	2	61%
Probability of Success		16%		11%		33%

Thus, well established companies with institutional knowledge and expansion opportunities can not only have the capital resources to use internal balance sheet funding, but enjoy improved probabilities of success based on their ability to make good decisions that lower their costs of financing (e.g., Melosh, 2017). Conversely, given these probabilities of success, private equity is justified in charging significantly higher costs of financing for wildcat projects.

Further work suggested is to explore the percentages of success assumed by the costs of capital charged. Such analysis will help to guide industry operators to better grasp the relationship between risk and financing, and will help to refine financial market expectations of value.

5. Conclusion

Prior to the work elaborated herein, a detailed dissection of costs of capital for geothermal projects and the variability in geothermal financing by project stage has been a neglected topic of wider discussion within the geothermal industry. This paper consolidates available information as cases for current and future geothermal project finance. While variability in historical financing rates can be explained by differences in probabilities of success, further work is needed to separate assumptions of decreased risk and success in future scenarios of financial markets.

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