

An Economic Valuation of a Geothermal Production Tax Credit

Brandon Owens



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Executive Summary

The United States (U.S.) geothermal industry has a 45-year history. Early developments were centered on a geothermal resource in northern California known as The Geysers. Today, most of the geothermal power currently produced in the U.S. is generated in California and Nevada. The majority of geothermal capacity came on line during the 1980s when stable market conditions created by the Public Utility Regulatory Policies Act (PURPA) in 1978 and tax incentives worked together to create a wave of geothermal development that lasted until the early 1990s. However, by the mid-1990s, the market for new geothermal power plants began to disappear because the high power prices paid under many PURPA contracts switched to a lower price based on an avoided cost calculation that reflected the low fossil fuel-prices of the early 1990s. State-level policies in California and Nevada also played a role in the reduction in demand for geothermal power. In particular, as part of an ongoing restructuring effort, utilities in California and Nevada began selling off electric generation capacity and did not have interest in bringing new capacity online.¹

Today, market and non-market forces appear to be aligning once again to create an environment in which geothermal energy has the potential to play an important role in meeting the nation's energy needs. Electricity supply shortages in California have greatly increased demand for reliable power sources such as geothermal energy; record levels of natural gas demand, coupled with infrastructure constraints, have resulted in volatile natural gas prices; and new concerns over environmental quality have led some states to enact renewable portfolio standards as part of their restructuring efforts. In this context, in 2001, multiple bills were introduced in the U.S. Congress that were intended to encourage geothermal energy development.

One potentially attractive incentive for the geothermal industry is the Production Tax Credit (PTC). The current PTC, which was enacted as part of the Energy Policy Act of 1992 (EPAct) (P.L. 102-486), provides an inflation-adjusted 1.5 cent per kilowatt-hour (kWh) federal tax credit for electricity produced from wind and closed-loop biomass resources. Proposed expansions would make the credit available to geothermal and solar energy projects. This report focuses on the project-level financial impacts of the proposed PTC expansion to geothermal power plants.

The key findings of this report are:

- For the two financing cases examined in this report, the PTC has the potential to be an effective incentive for helping geothermal power projects to become more economically competitive with fossil fuel plants.
 - In the Project Finance case, where 10-year non-recourse debt is used, for binary cycle projects, a 10-year 1.8 cent/kWh inflation-adjusted PTC has the potential to reduce the real levelized cost-of-electricity (LCOE) by 25% from 5.7 to 4.3 cents/kWh.² For flashed-steam projects, a PTC has the potential to reduce the real LCOE by 30% from 4.6 to 3.2 cents/kWh.
 - In the Corporate Finance case, where 10-year corporate debt is used, for binary cycle projects, a 10-year 1.8 cent/kWh inflation-adjusted PTC has the potential to reduce the real LCOE by 44% from 5.0 to 2.8 cents/kWh. For flashed-steam projects, a PTC has the potential to reduce the real LCOE by 44% from 4.1 to 2.3 cents/kWh.
- Tax appetite limitations and the Alternative Minimum Tax (AMT) can reduce the overall effectiveness of tax incentives such as the PTC, independent of the type of debt used in project financing. The effectiveness of the credit will be improved if the PTC legislation contains specific provisions that enable developers to configure around tax appetite limitations, and if the AMT level is reduced for geothermal developers who receive the credit.

¹ See Appendix A for legislative background on the geothermal industry.

² All values expressed in 2001 U.S. dollars unless otherwise noted.

- Debt-service coverage requirements can limit the impact of tax credits when non-recourse debt funds are involved in project financing. Increasing the level of equity in a project is the most common solution. However, this approach has the drawback of further constraining the equity-strapped geothermal industry. If the PTC were transferable to lending institutions, or if it were applicable as prepayment on any loans, then debt-service requirements would not limit the effectiveness of the credit. If these provisions were included in any new PTC legislation, then the ability of the credit to make geothermal projects more economically competitive would be increased.
- A number of factors determine the magnitude of the real levelized cost-of-electricity (LCOE) reduction due to the PTC. First, since the PTC is available for only 10 years, the face value of the credit must be annualized over the life of the project's power purchase agreement (PPA). Second, because the PTC is a tax credit, the annualized value must be multiplied by $1 \div (1-\tau)$, where τ is the developer's marginal income tax rate. Finally, project-specific financial constraints must be considered explicitly, because these factors can limit the ability of the PTC to reduce the electricity price.

1.0 Introduction

The Energy Policy Act of 1992 (EPAct) (P.L. 102-486) created a 10-year, inflation-adjusted 1.5 cent per kilowatt-hour (kWh) production tax credit (PTC) for electricity produced from wind and closed-loop biomass resources. The Section 45 PTC provides project owners with a credit against taxes for the first 10 years of plant operation. In late 1999, after a brief lapse, the PTC was retroactively extended through December 2001. In 2001, several bills were introduced in the U.S. Senate and House of Representatives which, if passed into law, would set the value of the credit to 1.8 cents/kWh and expand it to include solar, incremental hydropower, and geothermal electric sources. By providing targeted tax incentives, the U.S. government hopes to increase the supply of energy from socially beneficial energy resources.

The purpose of this report is to examine the project-level financial impacts of the proposed 10-year 1.8 cent/kWh PTC on geothermal power plants. Within this report, the PTC is compared to the existing Section 48 10% Investment Tax Credit (ITC). The numerical results presented in this report were developed using *Geothermal Cost-of-Electricity* (GEOCOE), a cost of electricity model developed by the National Renewable Energy Laboratory (NREL). *GEOCOE* simulates a detailed 30-year nominal dollar cash flow for geothermal power projects including project earnings, cash flows, and debt payment to calculate a project's 15-year levelized cost-of-electricity (LCOE), 15-year after-tax nominal Internal Rate of Return (IRR), and annual Debt-Service-Coverage-Ratios (DSCR).

2.0 Economic Valuation

2.1 Levelized Cost of Electricity

Typically, in order for a geothermal power project to become financially viable, project developers must secure an electricity sales contract with an electricity purchaser called a Power Purchase Agreement (PPA).³ In addition to spelling out the specific terms and conditions of the power sales agreement, the PPA typically specifies the first-year electricity sales price and the annual rate of price escalation that the purchaser will pay throughout the life of the contract. Generally, projects that can offer the lowest first-year electricity price are considered the most economically competitive. Therefore, project developers often use the first-year electricity price as an indicator of a project's attractiveness. However, because the terms and structure of PPAs vary greatly from project to project, the first-year electricity price is not a reliable indicator to use when comparing different projects.

The metric most commonly used to compare projects is levelized cost-of-electricity (LCOE). LCOE is the average price of electricity throughout the life of a power plant. To calculate a LCOE, a power project's expected revenue stream is discounted using a standard discount rate to yield the Present Value (PV) of the revenue stream.⁴ The PV is then converted to an annual stream of equal payments using a Uniform Capital Recovery Factor (UCRF). The annualized payment is then divided by the project's annual energy output to obtain the LCOE. LCOE can be a constant dollar value (which excludes inflation) or a current dollar value (which includes inflation) depending on whether the discount rate used to calculate the UCRF is real or nominal. Project developers prefer nominal LCOE because it more clearly reflects "real world" prices. However, government agencies performing long-term planning prefer real LCOE. Therefore, to accommodate both communities, both nominal and real LCOE values will be presented in this report.

For all of the analyses in this report, PPAs are assumed to have a 15-year length, equity investors are assumed to require an acceptable internal rate of return (IRR) within the first 15 years of the project life, and all project debt is assumed to be provided with a 10-year term unless otherwise noted. Further, starting in project year 16, we assume that projects are still owned and operated by the original owner; however, since both debt obligations and required returns to equity investors are fully met by this time, power sales need to generate only enough revenue to cover operating expenses and pay income taxes in year 16-30. In project year 16, owners are free to engage in another PPA, or to sell power at market prices.

The LCOE values presented here are calculated on a 15-year basis in accordance with the PPA term and the IRR analysis period. In this context, the LCOE values reflect the annualized cost of electricity through the 15-year PPA period. Further, for all of the analyses in this report, the expected inflation rate is assumed to be 2.8% and the nominal PPA escalation rate is assumed to be 2%. The expected inflation rate is consistent with the U.S. Energy Information Administration's (EIA) forecast of the Consumer Price Index (EIA 2001b). The PPA escalation rate is consistent with actual escalation rates for geothermal power project PPAs (Owens 2001a).

2.2 Financial Arrangements

Project Finance

Financial arrangements can significantly impact the value of tax credits such as the PTC. In general, when configuring a project, the financial arrangement selected depends on the financial capability of the project developer. Project developers that prefer to minimize risk to corporate assets, or those who do not have the capability to finance a project using debt that is secured against corporate assets, often look to commercial banks and other financial institutions to acquire a loan or to structure and sell bonds in order to pay for a large percentage of the project. Debt funds from lending institutions can be relatively expensive, and may

³ The power purchaser is usually a utility but may be a large industrial user, green power marketer, or other entity involved in the sale or use of electric power.

⁴ A utility's nominal weighted average cost of capital (WACC) of 8.6% instead of the developer's is used in this report as the discount rate in both the PV and UCRF calculations so that projects proposed by different developers can be compared on an even basis.

come with strings attached, because the debt is secured only with the assets of the project. This approach is known as non-recourse financing. Under this approach lenders require a time consuming, expensive, and elaborate due diligence process, before committing any funds. Within this report, "Project Finance" projects are assumed to be project financed with equity, provided with a 17% required after-tax nominal return to equity investors in the first 15 years of the project life, and non-recourse debt, provided at 7.5% over 10 years with a required minimum Debt-Service-Coverage-Ratio (DSCR) of 1.5, and an average DSCR of 1.75. The debt interest rate compares to the 30-year U.S. Treasury bond rate plus 2.0%.

Corporate Finance

On the other hand, if the developer is a corporation with a large financial capability and is willing to secure debt against corporate assets, then the project can be financed using a corporate finance approach. In this approach, project debt is secured against the assets of the entire company. Because the company's assets are at risk, debt funds for projects that are financed in this manner generally have favorable debt terms. In this report, "Corporate Finance" projects are assumed to be financed by a large corporation with both corporate equity, provided with a 17% required after-tax nominal return to equity investors in the first 15 years of the project life, and corporate debt, provided at a 6.5% interest rate with a 10-year maturity.⁵ The corporate debt interest rate compares to the 30-year U.S. Treasury bond rate, which was approximately at 5.5% in August 2001, plus a 1% spread.

Within both the Project Finance and Corporate Finance cases, projects are assumed to be financed with an optimal combination of debt and equity that minimizes the project's LCOE. Both financing approaches are summarized in Table 1.

Table 1: Financial Arrangements

<i>Financing Approach</i>	<i>Equity Terms</i>	<i>Debt Terms</i>	<i>Constraints</i>
Project Finance	Required 17% after-tax nominal internal rate of return (IRR) for equity percentage of capital structure. IRR calculated on the first 15 years of the project life.	Debt is non-recourse (project specific) financed over 10 years at an annual nominal interest rate of 7.5% (U.S. Treasury bond rate plus 2.0%).	There are three constraints: (1) the required equity IRR; (2) the minimum DSCR of 1.50; (3) and the average DSCR of 1.75.
Corporate Finance	Required 17% after-tax nominal internal rate of return (IRR) for equity percentage of capital structure. IRR calculated on the first 15 years of the project life.	Debt is corporate, (lenders have recourse through corporate assets) financed over 10 years at an annual nominal interest rate of 6.5% (U.S. Treasury bond rate plus 1.0%).	There are two constraints: (1) the required equity IRR; and (2) no negative after-tax cash flows. Executive management is mindful of the DSCR, but willing to accept very low values in order to retire debt within 10 years.

⁵ Project debt terms are generally 60-80% of the length of the PPA contract (Owens 2001b).

2.3 Technology Characteristics

Binary cycle and flashed-steam geothermal power plants will be examined in this report. The cost and performance estimates used for these technologies were taken from the Electric Power Research Institute's (EPRI) Renewable Energy Technology Characterizations (EPRI-DOE 1997), the jointly prepared book by EPRI and the U.S. Department of Energy (DOE). However, the average annual capacity factor and the annual O&M expense characteristics of these technologies were modified in response to more recent data (Owens 2001a). The technology characteristics used with *GEOCOE* are presented in Table 2.

Table 2: Geothermal Technology Characteristics

<i>Technology Characteristics</i>	<i>Binary Cycle</i>	<i>Flashed-Steam</i>
Plant Size (MW)	50	50
Total Capital Cost (1997 \$/kW)	\$2,112	\$1,444
Capital Cost Depreciable Percentage	82%	66%
Average Annual Capacity Factor	92%	92%
Annual Power Production (kWh)	402,960,000	402,960,000
Annual O&M Expense (2001 cents/kWh)	1.75 cent/kWh	2.00 cents/kWh
Royalty Fee (% of Revenue)	2.5%	3.5%
Plant Life	30	30

2.4 Tax Policy Cases

In order to evaluate the financial impact of a geothermal PTC, and to compare the PTC to the existing 10% ITC, three tax policy cases will be examined for each technology. These are: the "Base Case" with neither the ITC nor the PTC, the "ITC Case" which represents the current situation with a 10% ITC, and the "PTC Case" in which a 10-year 1.8 cent/kWh PTC is enacted in lieu of the existing 10% ITC. The tax policy cases examined in this report are presented in Table 3.

Table 3: Tax Policy Cases

<i>Tax Policy Case</i>	<i>ITC</i>	<i>PTC</i>	<i>Other Tax Benefits</i>
Base Case	No	No	Yes. Five-year accelerated depreciation, 15% percentage depletion allowance, first year expense for intangible exploration and well costs, and amortizable debt and equity related fees.
ITC Case: Represents the current policy environment.	10% of depreciable capital costs including construction loan interest.	No	Yes. Same as Base Case.
PTC Case	No	10-year 1.8 cent/kWh escalating with inflation.	Yes. Same as Base Case.

3.0 Results

The results presented in this report are based on simplifications of real-world conditions. As such, all of the numeric values shown here should be treated as indicators of overall trends, not as statement of fact. The actual cost of electricity from geothermal power plants may be higher or lower depending on resource conditions, transmission costs, and many other project-specific conditions.

In addition, it is important to note that the values presented in both the Corporate Finance and Project Finance cases assume that developers are able to absorb all of a project's tax benefits. However, in practice, many geothermal developers have limited tax appetites and are frequently subject to the Alternative Minimum Tax (AMT) (Owens 2001a). Although tax appetite limitations were not explicitly modeled in this analysis, it is clear that effectiveness of the PTC can be improved if the PTC legislation enables developers to configure around tax appetite limitations, and if the AMT level is reduced for geothermal developers who receive the credit.⁶

3.1 Project Finance

3.1.1 Binary Cycle

The results for binary cycle technology under the Project Finance arrangement are presented in Table 4.

Table 4: LCOE Results for Binary Cycle under the Project Finance Arrangement (2001 cents/kWh).

<i>Tax Policy Case</i>	<i>Real LCOE</i>	<i>Nominal LCOE</i>	<i>Equity Percentage</i>
Base Case	6.0	7.3	40%
ITC Case	5.7	6.8	45%
PTC Case	4.3	5.2	65%

As shown in Table 4, the real LCOE for a binary cycle plant, assuming the project is financed with 40% equity, is 6.0 cents/kWh in the Base Case. In the ITC Case, which represents the current policy environment, the real LCOE is 5.7 cents/kWh, assuming the project is financed with 45% equity. And, in the PTC Case, the real LCOE is 4.3 cents/kWh, assuming the project is financed with 65% equity. Thus, if developers are able to provide additional equity, the PTC has the potential to reduce the real LCOE by 28% from the Base Case, and 25% from the ITC Case, which represents the current policy environment.

Point A in Figure 1 shows the real LCOE in the Base Case where 40% equity is the optimal capital structure. Point B shows the real LCOE in the PTC Case where 65% equity is the optimal capital structure.⁷ Notice that the percentage of equity in the optimal capital structure is greater in the presence of the PTC. This is due to lender-imposed DSCR requirements. The DSCR is defined as operating income (operating revenue – operating expenses) divided by total debt payments (principal plus interest). Tax credits, such as the ITC and PTC, reduce income tax, but do not improve operating income. This means that if a project is subject to a DSCR requirement, as in the Project Finance arrangement modeled here, then the owner cannot reduce the electricity sales price in response to a tax credit without adversely affecting the DSCR. Instead, the developer must increase the level of equity in the project. This will improve the project's DSCR by reducing the debt payment, and it will allow a lower electricity sales price to be charged throughout the life of the project while maintaining a DSCR that is acceptable to the lender. However, there are limits to this approach. Beyond a project-specific optimal level, the investor's expected return becomes the binding constraint and additional equity actually drives up the real LCOE.

⁶ Developers can configure around tax appetite limitations using several different financing approaches. For example, developer's can obtain a limited partner with a large tax appetite that is willing to provide project equity. Developers may also have the option to engage in "sale lease-back" financing arrangements if allowable under the PTC legislation.

⁷ The "optimal" capital structure is the debt-to-equity ratio that minimizes the project's LCOE.

Increasing the share of equity in a project is an imperfect solution for developers because the industry is highly equity constrained. Geothermal developers typically seek to minimize equity and are unlikely to engage in a financing arrangement that involves more than 50% equity under any circumstances (Owens 2001a). A more realistic capital structure for small and medium sized-Independent Power Producers involves 20% equity and would yield a real LCOE of 7.4 cents/kWh (Point C in Figure 1). At 20% equity, because of the DSCR constraint, the net effect of the PTC is a substantial increase in the investor's IRR with no corresponding decrease in the project's real LCOE. However, if the PTC were transferable to lending institutions, or if it were applicable as prepayment on any loans, then debt-service requirements would not limit the effectiveness of the credit. If these provisions were included in any new PTC legislation, then the ability of the credit to make geothermal projects more economically competitive would be increased.

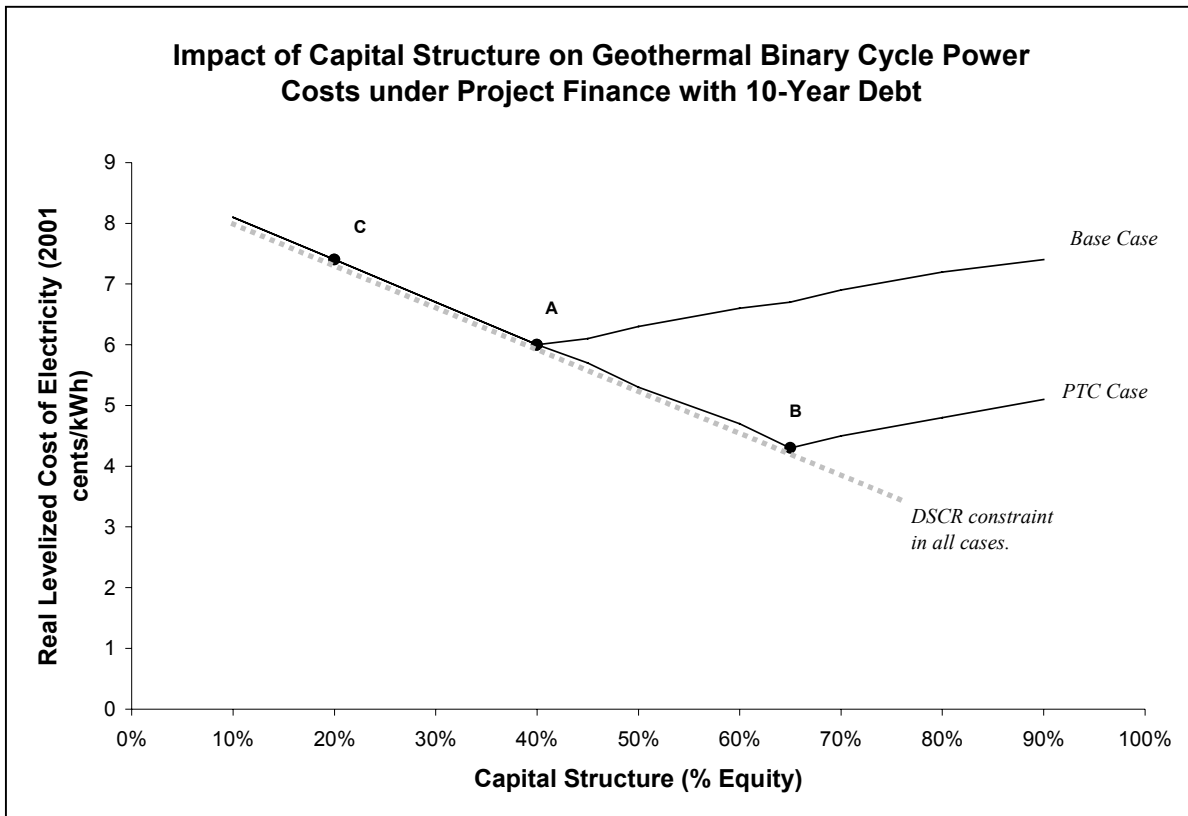


Figure 1: Impact of Capital Structure on Geothermal Binary Cycle Power Costs under Project Finance.

3.1.2 Flashed-Steam

The results for flashed-steam technology under the Project Finance arrangement are presented in Table 5. These results are consistent with those for binary cycle technology except that all of the LCOE values are lower because flashed-steam plants have lower equipment costs than binary cycle plants.

Table 5: LCOE Results for Binary Cycle under the Project Finance Arrangement (2001 cents/kWh).

<i>Tax Policy Case</i>	<i>Real LCOE</i>	<i>Nominal LCOE</i>	<i>Equity Percentage</i>
Base Case	4.8	5.7	42%
ITC Case	4.6	5.5	45%
PTC Case	3.2	3.9	87%

As shown in Table 5, the real LCOE for a flashed-steam plant, assuming the project is financed with 42% equity is 4.8 cents/kWh in the Base Case. In the ITC Case, which represents the current policy environment, the real LCOE is 4.6 cents/kWh, assuming the project is financed with 45% equity. And, in the PTC Case, the real LCOE is 3.2 cents/kWh assuming the project is financed with 87% equity. Thus, if developers provide additional equity, the PTC has the potential to reduce the real LCOE by 33% from the Base Case, and 30% from the ITC Case, which represents the current policy environment.

3.2 Corporate Finance

3.2.1 Binary Cycle

The results for binary cycle technology under the Corporate Finance arrangement are presented in Table 6.

Table 6: LCOE Results for Binary Cycle under the Corporate Finance Arrangement (2001 cents/kWh).

<i>Tax Policy Case</i>	<i>Real LCOE</i>	<i>Nominal LCOE</i>	<i>Equity Percentage</i>
Base Case	5.3	6.4	33%
ITC Case	5.0	6.1	39%
PTC Case	2.8	3.3	27%

As shown in Table 6, the real LCOE for a binary cycle plant, assuming the project is financed with 33% equity, is 5.3 cents/kWh in the Base Case. In the ITC Case, which represents the current policy environment, the real LCOE is 5.0 cents/kWh, assuming the project is financed with 39% equity. And, in the PTC Case, the real LCOE is 2.8 cents/kWh, assuming the project is financed with 27% equity.

Point A in Figure 2 shows the real LCOE in the Base Case where 33% equity is the optimal capital structure. Point B shows the LCOE in the PTC Case where 27% equity is the optimal capital structure. Notice that, unlike the Project Finance arrangement, the percentage of equity in the optimal capital structure decreases in the presence of the PTC. This is due to the presence of the "Phantom Income" constraint. This constraint is sometimes imposed by project developers to ensure that a project does not generate an after-tax loss during any year. Because the debt term in this analysis is assumed to be only 10 years to reflect current market conditions (Owens 2001b), this constraint is binding in the Base Case for equity levels less than 33%.⁸

As indicated in Table 6, in the Corporate Finance case, the PTC has the potential to reduce the real LCOE by 2.5 cents/kWh or 47% from the Base Case. If we correct for differences in capital structure (remember, in all of the cases, the capital structure is optimized to reduce the real LCOE) by assuming 33% equity in the PTC Case (Point C in Figure 2), then the difference in the real LCOE between the two cases decreases to 2.3 cents/kWh. This is equivalent to the face value of the credit divided by $(1-\tau)$,⁹ where τ is the developer's marginal income tax rate, annualized over the 15-year length of the PPA.¹⁰

It is also possible that project developers will decrease the debt-financing period in the presence of the PTC. For illustrative purposes, the thin dotted line in Figure 2 represents the real LCOE in the Base Case with 30-year debt at a nominal interest rate of 6.5%.¹¹ This arrangement more closely resembles the financing structure of an investor-owned (IOU) where debt can be spread out over the entire 30-year financial life of the project. Notice that the difference between the PTC Case and the 30-year debt Base Case is substantially lower than the difference between the PTC Case and the 10-year debt Base Case.

⁸ This constraint is binding in the Base Case starting in project year 7 after the capital costs have been fully depreciated.

⁹ See Appendix B for a mathematical derivation of the PTC+ $(1-\tau)$ rule.

¹⁰ See Appendix D for an illustration of this 15-year annualization.

¹¹ For consistency, in the 30-year debt Base Case, the 15-year IRR and LCOE calculation methods have been converted to 30-year calculations.

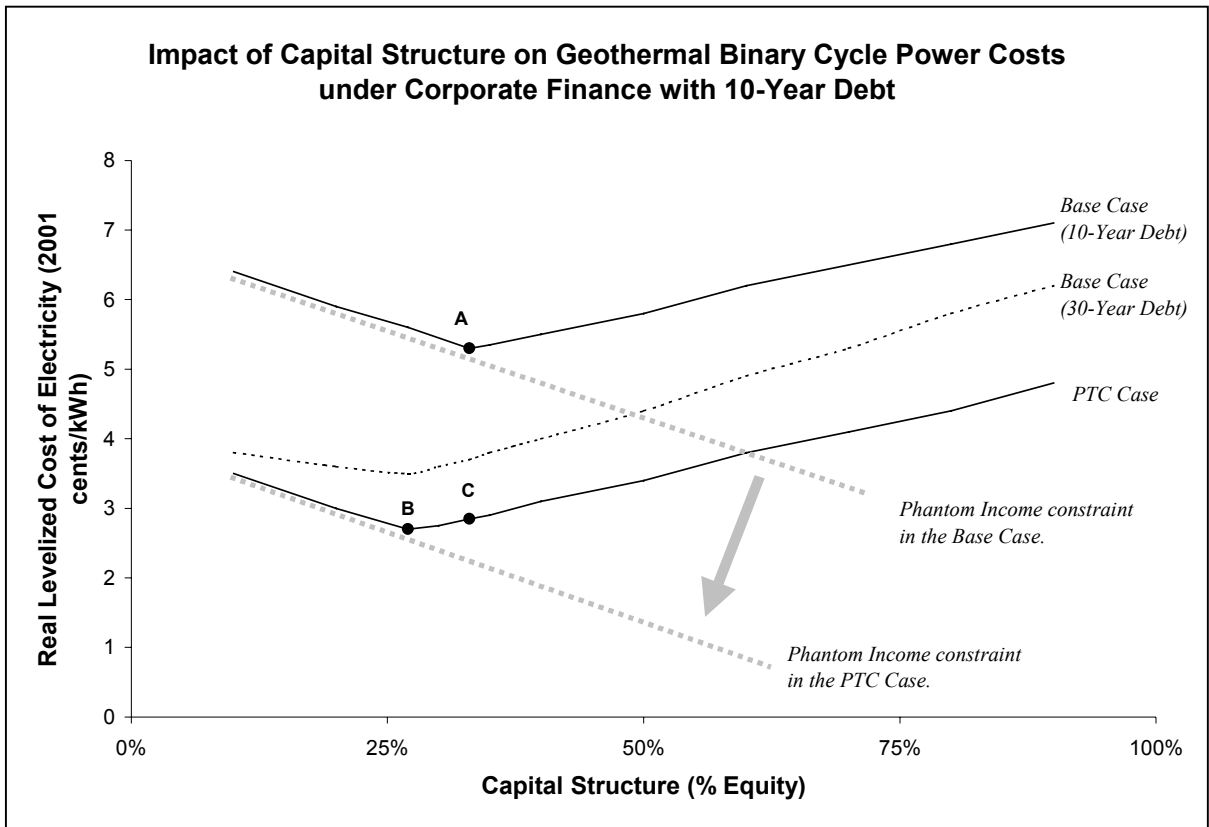


Figure 2: Impact of Capital Structure on Geothermal Binary Cycle Power Costs under Corporate Finance.

3.2.2 Flashed-Steam

The results for flashed-steam technology under a Corporate Finance arrangement are presented in Table 7. These results are consistent with those for binary cycle technology except that all of the LCOE values are lower because flashed-steam plants have lower equipment costs than binary cycle plants. As shown in Table 1, the total capital cost of a flashed-steam project is assumed to be \$1,444/kW (1997 \$'s) compared to a cost of \$2,112 (1997 \$'s) for binary cycle technology. Flashed-steam projects do have higher O&M costs (2.00 cents/kWh versus 1.75 cents/kWh for binary cycle,) but the difference is not enough to overcome the reduced capital cost.

Table 7: LCOE Results for Binary Cycle under the Corporate Finance Arrangement (2001 cents/kWh).

<i>Tax Policy Case</i>	<i>Real LCOE</i>	<i>Nominal LCOE</i>	<i>Equity Percentage</i>
Base Case	4.3	5.1	34%
ITC Case	4.1	5.0	39%
PTC Case	2.3	2.7	30%

As shown in Table 7, the real LCOE for a flashed-steam plant, assuming the project is financed with 34% equity is 4.3 cents/kWh in the Base Case. In the ITC Case, which represents the current policy environment, the real LCOE is 4.1 cents/kWh, assuming the project is financed with 39% equity. And, in the PTC Case, the real LCOE is 2.3 cents/kWh assuming the project is financed with 30% equity.

4.0 Cost to the U.S. Treasury

An important question in the examination of the geothermal PTC is how much the incentive will cost the U.S. Treasury. The answer to this question depends on both the project-level costs and on the number of projects that are initiated as a result of the PTC. The project-level costs of the PTC have been evaluated in this report; however, no quantitative attempt has been made to estimate the macroeconomic impact. Still, some observations can be made about the potential cost to the U.S. Treasury even in the absence of a complete macroeconomic assessment.

From the perspective of the U.S. Treasury, it is likely that the net cost of the PTC would be insignificant or perhaps even negative, because, as Jenkins et al. (1998) have shown, the tax loads associated with constructing and owning geothermal projects are often higher than the load for competing fossil fuel plants under current tax code. In fact, a recent analysis of geothermal federal royalties and income taxes found that federal taxation on geothermal power is about three to four times that of electricity produced from a new natural-gas combined-cycle power plant (Entingh 1998). These studies indicate that if new federal incentives are enacted which encourage the increased geothermal development as an important complement to traditional energy resources, and if the total government cost of the new incentives is less than the difference between the tax loads of the geothermal and conventional generation technologies, then the government will actually increase its revenue through the enactment of such policies. Although additional research is needed, these initial analyses indicate that the Treasury exposure due to a geothermal PTC may be very limited.

Appendix A: Legislative Background

Geothermal energy is a power source that produces electricity with minimal environmental impacts. Since geothermal power production entails no combustion, its atmospheric emissions are limited. Geothermal electricity is also attractive because at some sites it is economically competitive, reliable, and commercially proven. For these reasons, U.S. federal and state governments have historically taken an interest in increasing the supply of geothermal electricity. Federal government involvement began with the passage of the Geothermal Steam Act of 1970 (P.L. 91-581). This law was intended to make geothermal resources more widely accessible by authorizing the U.S. Department of Interior to lease geothermal resources on federal lands.¹²

After the 1973 Arab oil embargo and ensuing energy crisis, the U.S. government took an even stronger interest in promoting the production of geothermal energy. Congress passed the Geothermal Energy Research, Development and Demonstration Act of 1974 (P.L. 93-410), which established a geothermal research and development (R&D) program and a loan guarantee program that ultimately issued five loan guarantees totaling \$136 million (Williams 1982). The program sought to help make private capital available to the geothermal industry. In the 1970s, the U.S. geothermal industry was unable to attract sufficient capital for project development because commercial bankers were unwilling to take risks on an industry about which they knew little. By sharing some of the risk of early geothermal development, the goal of the loan guarantee program was to provide a capital impetus to the industry.¹³

The Public Utility Regulatory Policies Act of 1978 (PURPA) (P.L. 95-617) set the stage for a geothermal power project boom beginning in the early 1980s. Prior to PURPA, there was little incentive for electric utilities to purchase electricity generated by geothermal power plants. Under the provisions of PURPA, however, utilities were required to buy power from qualifying power plants at rates that were equivalent to the cost that the utility would otherwise have to spend to generate or procure power. When PURPA was passed, the so-called “avoided” cost of power – which is calculated by forecasting future energy prices – was high because oil prices were at historic highs and expected to continue to increase. As a result, utilities entered into long-term agreements to purchase electricity from geothermal power plants at (what later turned out to be) above market rates. By creating a stable and secure market, PURPA insulated geothermal developers from market risk and made geothermal projects attractive for both debt lenders and equity investors.

The Energy Tax Act of 1978 (ETA) (P.L. 95-618) made geothermal power projects even more attractive by allowing for depletion of geothermal deposits by instituting a percentage depletion allowance rate of 10 percent for 1978 through 1979, and 15 percent thereafter (CCH 1997). ETA also created a 10% Energy Investment Tax Credit (ITC) for geothermal and other renewable energy technologies. The ITC was increased to 15% from 1980 through 1986. The ITC, in addition to an existing general 10% investment tax credit, allowed some geothermal developers to receive income tax credits of up to 25% of the cost of geothermal technology through the mid-1980s.

The Economic Recovery Tax Act of 1981 (ERTA) (P.L. 97-340) improved the attractiveness of geothermal projects even further by allowing for five-year accelerated depreciation of geothermal equipment. In 1986, the Tax Reform Act (P.L. 99-514) repealed the general 10% investment tax credit, but extended the 10% geothermal EITC through 1991. In 1992, the 10% ITC was permanently extended by EPAct.

¹² Some believe that this act contained overly strict requirements for assessing the environmental impacts of proposed geothermal projects. As a result, the majority of lease applicants never obtained leases (Gorschboth 1980). The Energy Security Act (H.R. 2436), which was introduced in the U.S. House of Representatives on July 10, 2001, is intended to provide relief from the requirements of the Geothermal Steam Act. The success of the PTC will depend in part on the passage of legislation such as H.R. 2436 which facilitates the federal leasing process.

¹³ Observers vary in their assessment of the act. Some believe that the program was unduly complex (Williams 1982). However, others point to the federal loan guarantee used by ORMAT in 1980 to launch the first commercial-scale binary plant in the U.S. as proof of the Act's success. The Renewable Energy Loan Guarantee Act (H.R. 2774), which was introduced in the U.S. House of Representatives on August 2, 2001, is intended to revive the loan guarantee program for geothermal and other renewable energy resources.

Starting in the early 1980s, the unique market conditions created by PURPA (1978), and the tax incentives enacted under ETA (1978) and ERTA (1981), worked together to create a wave of geothermal development that lasted for a decade. Capacity quadrupled between 1980 and 1994 (EIA 1995). Most of the capacity was installed in the mid- to late 1980s; about half was installed as independent power projects under PURPA contracts.

However, by 1992, the market for new geothermal projects began to decline when contracts executed under PURPA, which had a 10-year schedule of high prices, reverted to a lower price based on new avoided cost calculations. This left geothermal power plants to compete directly with natural gas-fired generation technologies that were able to produce electricity at 2-3 cents/kWh as a result of low natural gas prices and technological improvements. State policies in California and Nevada also played a role in the reduction in the demand for geothermal power. In California, as a result of ongoing restructuring of the power industry, utilities began selling off their electric generation capacity and did not have interest in bringing new capacity online. And in Nevada, the elimination of Integrated Resource Planning (IRP) reduced the incentive for utilities to diversify their generation portfolios with renewable energy resources. As a result of these conditions, U.S. geothermal generating capacity stagnated in the 1990s, edging up only slightly from 2.72 GW in 1990 to 2.98 MW in 1999 (EIA 2001a).

In 2000 and 2001, market and non-market forces began to align once again to create an environment in which geothermal energy has the potential to play an important role in meeting the nation's energy needs. Electricity supply shortages in California, in part a result of the generation divestiture of the 1990s, have greatly increased demand for reliable power sources such as geothermal energy. Record levels of natural gas demand, coupled with infrastructure constraints, have produced record natural gas price volatility. In addition, new concerns over environmental quality and fuel diversification have prompted many developers and power purchasers to consider geothermal energy. Finally, as part of their ongoing restructuring efforts, several states have enacted or are considering legislation specifying renewable portfolio standards.

In 2001, several bills were introduced in the U.S. Congress that propose an expansion of the 10-year wind and closed-loop biomass PTC, enacted under EPAct, to geothermal power projects. If passed into law, these bills would provide geothermal developers with an inflation-adjusted 1.8 cent/kWh credit against taxes for the first 10 years of project operation. The purpose of the geothermal PTC is to reduce the price of electricity from geothermal power plants in order to encourage increased demand for, and subsequent supply of, geothermal electricity. Whether or not the PTC will be successful in achieving this objective will depend greatly upon the project-level financial impacts of the PTC. These impacts are the focus of this report.

Appendix B: PTC ÷ (1-τ) Mathematical Derivation

The actual results presented in the main body of this report were developed using a detailed cost of electricity spreadsheet model. However, for illustrative purposes, in this Appendix we present a mathematical derivation of the change in unit revenue (e.g. electricity price or real LCOE) induced by the PTC.¹⁴

In order to determine the change in unit revenue induced by the PTC, we must first define the following terms:

τ = Marginal income tax rate (%), see Appendix C

R_t = Revenue (cents/kWh) in year t,

IT_t = Income tax (cents/kWh) in year t = $R_t \tau$,

PTC = Production Tax Credit (cents/kWh) available for the first 10 years of the project,

FT_t = Final tax bill (cents/kWh) in year t = $IT_t - PTC_t$, and

AT_t = After-tax cash flow (cents/kWh) in year t = $R_t - FT_t$.

Next, we find that $AT_t = R_t - FT_t$ can be reduced to $AT_t = R_t(1-\tau) + PTC_t$ in the following manner,

$$AT_t = R_t - FT_t = R_t - IT_t + PTC = R_t - R_t \tau + PTC_t = R_t(1-\tau) + PTC.$$

Now, to determine the change in revenue induced by the PTC_t holding AT_t constant to ensure that investor's receive the same rate of return, we can define R_t' as the required revenue in the absence of the PTC , and we can define R_t'' as the required revenue in the presence of the PTC_t . If we assume that AT_t is held constant with or without the PTC_t , we can determine the change in revenue using following equality,

$$R_t'(1-\tau) = R_t''(1-\tau) + PTC$$

Dividing by $\frac{1}{(1-\tau)}$ yields,

$$R_t' = R_t'' + \frac{PTC}{(1-\tau)}$$

Or equivalently,

$$R_t' - R_t'' = \frac{PTC}{(1-\tau)}.$$

Thus, we find that the difference in revenue in year t ($R_t' - R_t''$) with and without the PTC, while holding AT_t constant, is equal to

$$\frac{PTC}{(1-\tau)}.$$

It is important to note that this is the maximum PTC induced unit revenue change. This value may need to be annualized over the term of the PPA depending upon project-specific conditions, and the value will be further reduced in the presence of lender imposed debt-service constraints, and/or corporate imposed Phantom Income constraints.

¹⁴ For simplicity, we have omitted debt payments, operating expenses, and tax deductions from the mathematical equations presented in this Appendix (i.e. revenue = taxable income). If these factors were included here, the complexity of the equations would be substantially increased, but the final result would remain unchanged.

Appendix C: Derivation of τ

In order to determine the appropriate tax rate, τ , to be used in calculating the before-tax PTC value, $PTC \div (1-\tau)$, we must first define the following terms:

f = Marginal federal income tax rate (%),

s = Marginal state income tax rate (%),

R_t = Revenue (cents/kWh) in year t , and

PTC = Production Tax Credit (cents/kWh) available for the first 10 years of the project.

Further, as in Appendix B, we define R_t' as the required revenue in the absence of the PTC , and we define R_t'' as the required revenue in the presence of the PTC .¹⁵ We start by assuming that after-tax income, AT_t , is held constant with or without the PTC_t , to ensure that investors receive the same rate of return,

$$R_t' - fR_t' - sR_t' + fsR_t' = R_t'' - fR_t'' - sR_t'' + fsR_t'' + PTC.$$

By simplification we have,

$$R_t'(1 - f - s + fs) = R_t''(1 - f - s + fs) + PTC.$$

Dividing by $\frac{1}{(1-f-s+fs)}$ yields,

$$R_t' = R_t'' + \frac{PTC}{(1 - f - s + fs)}.$$

Or equivalently,

$$R_t' - R_t'' = \frac{PTC}{(1 - f - s + fs)}.$$

Such that,

$$\frac{PTC}{(1 - f - s + fs)} = \frac{PTC}{(1 - \tau)},$$

if and only if,

$$\tau = (1 - f - s + fs).$$

¹⁵ For simplicity, we have omitted debt payments, operating expenses, and tax deductions from the mathematical equations presented in this Appendix (i.e. revenue = taxable income). If these factors were included here, the complexity of the equations would be substantially increased, but the final result would remain unchanged.

Appendix D: Maximum Annualized PTC Value

When projects are engaged in PPAs that have a longer term than the 10-year period over which the PTC is available, then the PTC induced unit revenue reduction (e.g. the change in electricity price with and without the PTC) is annualized over the length of the PPA. In these cases, the PTC induced unit revenue reduction will be less than $PTC \div (1-\tau)$.

To determine the annualized revenue reduction value of the credit (ignoring financing limitations),¹⁶ we first compute the present value of the credit, $PV(PTC)$. Since the credit is available for 10 years, we can calculate the present value as,

$$PV(PTC) = \sum_{i=1}^{10} \frac{PTC}{(1-\tau)} \times \frac{1}{(1+d_r)^i},$$

Where,

τ = Marginal income tax rate (%),

PTC = Production Tax Credit (cents/kWh) available for the first 10 years of a project's life; and

d_r = the real discount rate used for LCOE calculations.

This can be simplified to,

$$PV(PTC) = \frac{PTC}{(1-\tau)} \sum_{i=1}^{10} \frac{1}{(1+d_r)^i}.$$

If we let $d_r = 5.6\%$, if we let $PTC = 1.8$ cents/kWh, and if we assume that τ is 40% then,

$$PV(PTC) = \frac{1.8}{(1-0.40)} \sum_{i=1}^{10} \frac{1}{(1+0.056)^i} \approx 3.0 \times 7.49 \approx 22.5.$$

We can annualize this value over the PPA term by multiplying the $PV(PTC)$ times the Uniform Capital Recovery Factor ($UCRF$) which is defined as,

$$UCRF = \frac{d_r(1+d_r)^N}{(1+d_r)^N - 1}$$

Where N = the length of the PPA. If we assume that $N=15$, in accordance with the examples presented in this report then,

$$UCRF = \frac{0.056_r(1+0.056)^{15}}{(1+0.056)^{15} - 1} \approx 10.1\%.$$

We can now calculate the annualized present value of the credit, $APV(PTC)$, as,

$$APV(PTC) = PV(PTC) \times UCRF$$

$$APV(PTC) = 22.5 \times 0.101$$

$$APV(PTC) \approx 2.3.$$

Thus, we can see that, under these assumptions, the annualized revenue reduction value of the PTC is approximately 2.3 cents/kWh.

¹⁶ The actual results presented in the main body of this report were developed using a detailed cost of electricity spreadsheet model. However, for illustrative purposes, in this Appendix we present a mathematical derivation of the annualization of the PTC-induced change in unit revenue.

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