Perspectives on the Economics of Geothermal Power

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ABSTRACT

Geothermal power developers typically engage in long term, 10 to 20 years, power sales agreements during the development phase. Long term power sales agreements provide better financing conditions and cash flow stability for geothermal projects. In deregulated wholesale power markets long term power contracts are structured around the future expectations of market prices. In this study we will attempt to discuss the economics of geothermal power plants in western power markets. The study will analyze the historical price movements in the major western power trade hubs and the critical factors affecting the prices. We will introduce a Stochastic Geothermal Cost Model (SGCM) and compare the levelized cost of geothermal energy against the historical price levels and future expectations. The study will also discuss the impacts of a production tax credit and renewable portfolio standards on the economics of geothermal power.

1. Introduction

This paper presents the big picture discussion of geothermal power generation economics and characteristics of the power markets in the Western United States where the hydrothermal geothermal energy resources and all of the existing geothermal plants are located. The purpose is connecting the dots between geothermal energy and electricity markets. The scope of the power markets discussion is limited with the subjects relevant to geothermal power generation. In our power market analysis we mostly rely on historical data.

The paper is composed of five sections in the first three sections we provide overview of western power markets, historical price trends and potential future trends in the energy markets. In the fourth section we analyze the long term levelized cost of geothermal power generation and discuss the incentives available to geothermal power development projects. In the fifth section we compare the levelized cost of geothermal power with the historical and projected prices. In the last section we list the conclusions and recommendations to improve the economy of geothermal power development projects.

2. Energy Markets and Pricing Points

The North American grid is composed of three interconnections which are connected to each other with only DC ties. Almost all of the U.S. geothermal potential is located in Western Electricity Coordinating Council (WECC) footprint. WECC is responsible for coordinating and promoting the formation of reliable electric power system in its footprint. WECC supports competition in power markets, provides a medium for resolution of transmission access related disagreements, assure open access to transmission among members [1].

WECC is divided into four sub-regions (See Figure 2, overleaf), 1) Northwest Power Pool (NWPP) area, 2) Rocky Mountain

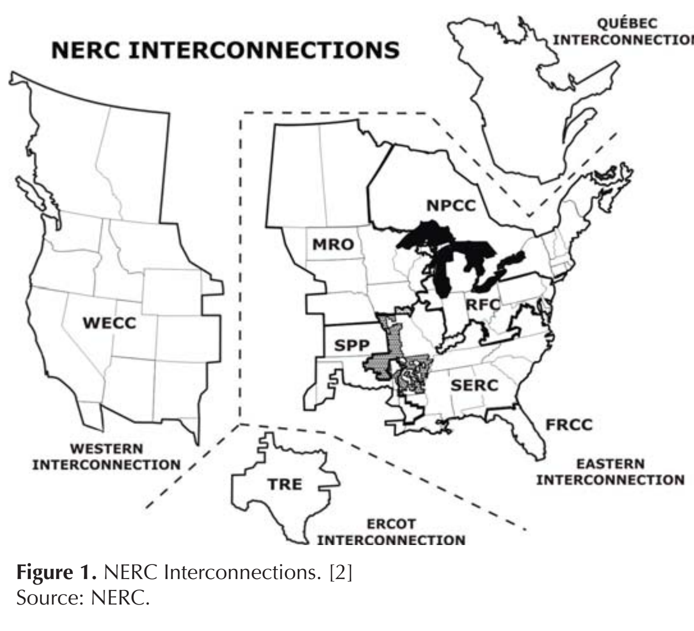

Figure 1. NERC Interconnections. [2]
Source: NERC.

Power Area (RMPA), 3) Arizona/New Mexico/Southern Nevada Power Area (Desert Southwest) and 4) California/Mexico Power Area. Division of WECC is natural and mostly based on geographical and climatic factors [1]. Note that WECC sub-region four mostly overlaps with the California Independent System Operator (CAISO) footprint. California ISO is a transmission operator and balancing authority who maintains wholesale energy markets. This area also includes the major load centers in the region and the flow of power is generally towards this area. This is especially the case for the hydro power located in the north.

In Figure 2 major energy pricing points in the region are shown with dark squares. For the purpose of simplicity we will use a single gas pricing point, PG&E Citygate, in the study (See Figure 2). Historically price levels at these pricing hubs are accepted as representative of the regional prices and used as market indicators.

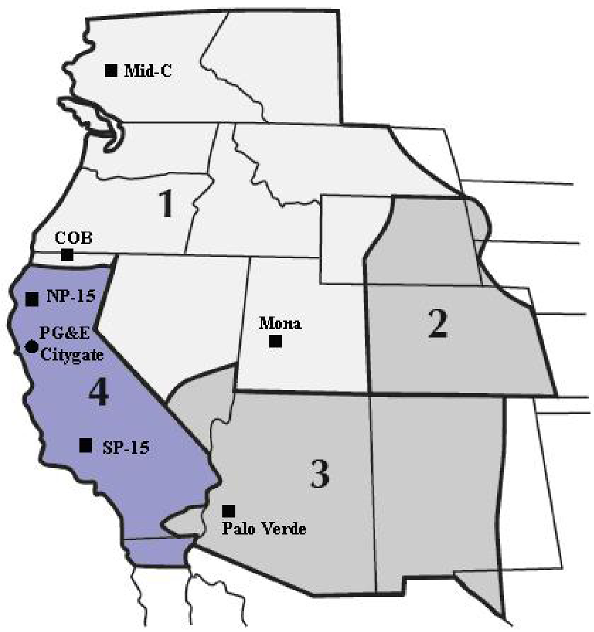

Figure 2. WECC Sub-Regions and Major Pricing Points. [1]
Source: WECC, 10-Year Coordinated Plan Summary.

Table 1. WECC U.S. Capacity Mix. [3]
Source: WECC

Type	2007 Summer Capacity (MW)
Nuclear	9,488
Hydro	44,601
Pumped Storage	4,681
Geothermal	**1,823**
Wind	1,050
Coal	30,352
Natural Gas - Combined Cycle	40,437
Natural Gas/Oil - Peaker	13,971
Oil/Gas Steam	18,810
Other	2,571
Total	**167,784**

Gas fired units form the 44% of the installed capacity in the U.S. portion of the WECC. This is followed by hydro and coal (See Table 1). Historically gas fired units are price setters in majority of the WECC U.S. region.

3. Historical Trends

Historical variation of monthly power and natural gas prices are shown in Figure 3. The correlation between natural gas and power prices are strong in the region. Looking at monthly historical data between 2007 and 2009 the correlation between PG&E Citygate natural gas prices and major energy pricing hubs ranges between 77% and 95% (See Table 2). Note this clearly indicates that natural-gas fired units are the price setters most of the time in these hubs.

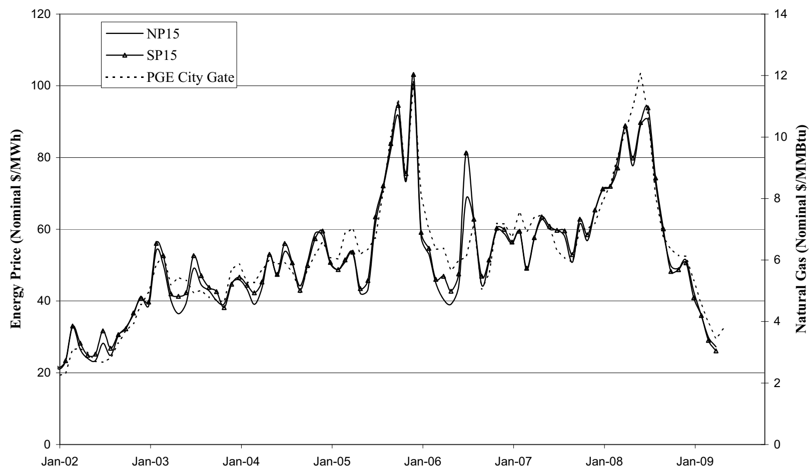

Figure 3. Historical Power and Natural Gas Prices. [4,5]
Source: Intercontinental Exchange (ICE), Over the Counter (OTC) North American Power Indices and North American Natural Gas Indices.

Table 2. Correlation of Energy and Natural Gas Prices in WECC. [4,5]
Source: Intercontinental Exchange (ICE), Over the Counter (OTC) North American Power Indices and North American Natural Gas Indices.

Power Price Hub	Correlation with PG&E Citygate Gas Prices
NP15	95%
SP15	95%
Palo Verde	94%
MID-C	77%
COB	90%
Mona	75%
Average	**88%**

Market Implied Heat Rate (IHR) is defined as the ratio of energy price to the natural gas price and commonly used as a market indicator. IHR is an especially relevant indicator in markets where natural gas fired units dominantly set the price. Variation of monthly historical IHRs for 2002 – 2009 period is shown in Figure 4. In general IHR is a function of installed capacity, transmission constraints and demand. It is not uncommon to observe some seasonal characteristics in IHRs due to hydro availability and ambient temperatures.

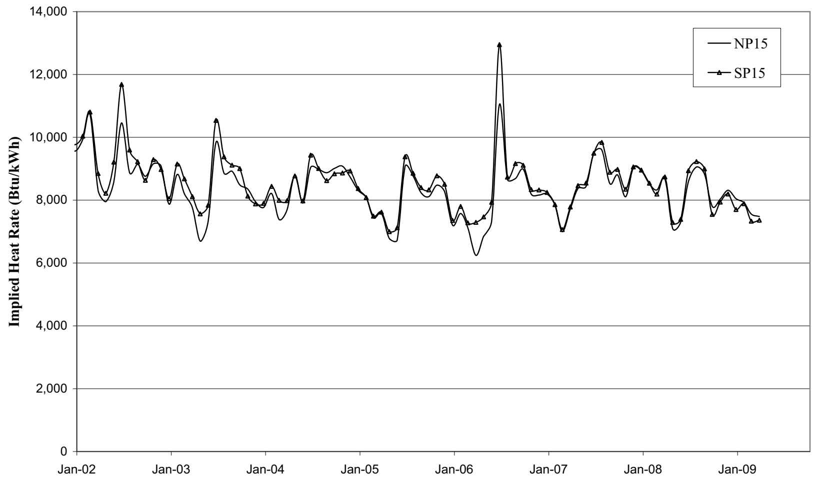

Figure 4. Historical Market Implied Heat Rates. [4,5]
Source: Intercontinental Exchange (ICE), Over the Counter (OTC) North American Power Indices and North American Natural Gas Indices.

Average historical IHRs for major WECC price hubs range between 7,500 Btu/kWh and 8,600 Btu/kWh. Market IHRs are important market indicators for developers. Low IHRs indicate that baseload generators such as wind, coal, hydro, geothermal, and nuclear are frequently on the margin and set the price. The changes in IHR trends occur when the supply mix changes in the region. For example penetration of high amounts of wind generation has changed the IHR dynamics of the markets in western Texas recently. Looking at Figures 3 and 4 simultaneously one can notice that the volatility in energy prices in 2008 and 2009 is not reflected on IHRs in Figure 4. This is because the supply mix has not changed significantly from one year to another. If the average market IHR is at 8,000 Btu/kWh and the natural gas price is at $10/MMBtu energy price is calculated at $80/MWh (8,000*10/1000). If the gas price suddenly drops to $4/MMBtu level energy price is calculated at $32/MWh (8,000*4/1000). This is why the fundamentals based market penetration models plays critical role in forecasting trends in energy markets. These models forecast the future capacity mix and consequently market IHRs.

A geothermal power plant selling into an energy market is a price taker and subject to market volatilities. As we discussed above most of the volatility comes from natural gas prices. Geothermal developers usually engage in long term power sales contracts to hedge themselves and obtain better financing terms. Long term power purchase agreements (PPAs) are usually based on long term expectation of the market prices and include the capacity and renewable energy credit (REC) payments. In the absence of a long term PPA, geothermal power plants always have the option to sell their power in wholesale markets. In that case their cash flows will be exposed to volatility in natural gas prices. Financing may also be more difficult to obtain. Recent drop in natural gas prices has also shown the importance of locking energy prices upfront in renewable projects. Note however it may not always be possible to find an attractive PPA in the beginning of the project. In that case alternative hedging strategies based on complex cross commodity hedge structures can be considered. Geothermal power plants have low production costs, almost zero emissions and run 24x7. These features make the geothermal plants very attractive for hedging arrangements.

Table 3. Historical Market Implied Heat Rates in WECC. [4,5]
Notes: Source: Intercontinental Exchange (ICE), Over the Counter (OTC) North American Power Indices and North American Natural Gas Indices (PG&E Citygate Hub).

Year	NP15	SP15	Palo Verde	MID-C	COB	Mona
2002	9,213	9,525	8,750	6,873	8,109	n/a
2003	8,257	8,621	8,017	7,136	7,712	n/a
2004	8,458	8,564	7,573	7,204	7,846	n/a
2005	7,988	8,161	7,410	7,089	7,561	8,325
2006	8,006	8,480	7,557	6,821	7,528	7,715
2007	8,428	8,548	7,709	7,317	8,071	7,687
2008	8,291	8,330	7,245	7,138	7,900	6,999
Average	**8,377**	**8,604**	**7,752**	**7,083**	**7,818**	**7,682**

4. Future Trends and Revenues

As discussed in the previous chapter energy prices are strongly correlated with natural gas prices. Although major developments such as change in supply mix or introduction of a new environmental regulation policy such as carbon emission regulations can have significant impacts on the markets, future trends are likely to be set by the natural gas prices. Monthly average natural gas price at PG&E Citygate between 2002-2009 YTD period is calculated at $6.2/MMBtu with a standard deviation of $2.1/MMBtu. In Table 4 we show the natural gas prices and corresponding energy prices at historical mean and plus/minus one and two standard deviations. We assumed that the IHR will be at 8,000 Btu/kWh based on historical data. Note the table relies on historical data to create a range of outcomes for the future and ignores the impact of upcoming CO_2 regulations or potential change in the supply mix.

Table 4. Energy Prices at different natural gas prices and 8,000 Btu/kWh IHR.
Notes: 1: μ = mean
2: σ = standard deviation

Gas Price	Gas Price ($/MMBtu)	Implied Heat Rate (Btu/kWh)	Energy Price ($/MWh)
μ - 2σ	2.0	8,000	16.2
μ - σ	4.1	8,000	32.8
μ	6.2	8,000	49.3
μ + σ	8.2	8,000	65.8
μ + 2σ	10.3	8,000	82.3

The range of energy prices presented in Table 4 does not include payments for capacity, renewable energy credits nor production tax credits. Discussion of capacity prices is not in the scope of this paper. However depending on the regional market structure and reliability requirements power plants are paid for their contribution to the installed capacity. California ISO recently suggested a \$41/kW-yr capacity price to be paid to the units for their contribution to the reserve margin capacity in some of its zones [6]. Geothermal power plants are eligible to receive payments almost 100% of their net capacity. For the purposes of this study we will assume a geothermal power plant will have an additional \$41/kW-yr of revenue on top of its energy revenues. In addition to energy and capacity revenues geothermal power plants are eligible to receive \$21/MWh production tax credit during the first 10 years of their operation. At a 7% discount rate, the PTC corresponds to \$14/MWh levelized revenue for 20-years. Energy price with PTC and capacity payments added are presented in Table 5.

Geothermal plants are also eligible to receive renewable energy credits for their contribution to state renewable portfolio standards (RPS). These payments are based on RPS targets set by each state. Depending on the amount of installed renewable energy and RPS target REC can range extensively. We will discuss the appropriate amount of REC for geothermal in the following sections.

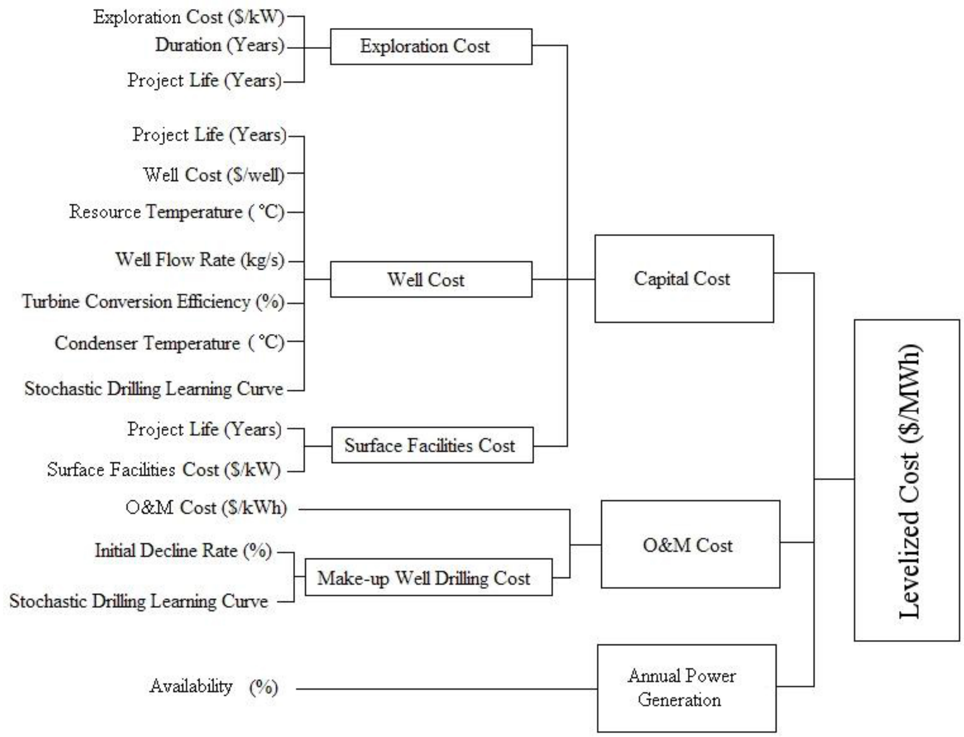

Figure 5. Basic Scheme of the Stochastic Geothermal Cost Model (SGCM).

Table 5. Energy prices at different natural gas prices and 8,000 Btu/kWh IHR. Notes: 1. Assumes 90% availability.

Gas Price	Gas Price (\$/MMBtu)	Energy Price (\$/MWh)	Energy Price with Capacity Payment (\$/MWh)	Energy Price with PTC and Capacity Payment (\$/MWh)
$\mu - 2\sigma$	2.0	16.2	21.4	35.4
$\mu - \sigma$	4.1	32.8	38.0	52.0
μ	6.2	49.3	54.5	68.5
$\mu + \sigma$	8.2	65.8	71.0	85.0
$\mu + 2\sigma$	10.3	82.3	87.5	101.5

5. Levelized Cost of Geothermal Energy

Levelized cost is a metric used by decision makers to understand and evaluate the all-in unit cost of generating power from different energy sources. It includes all project expenses such as investment cost, O&M costs, taxes, cost of equity and debt and is expressed as dollars per megawatt-hours (\$/MWh). In order to calculate the levelized cost of a power plant all expenses should be converted to annualized payments throughout the project life. Annualized cost is then divided by the average annual generation (MWh). There are two main components of the levelized cost, fixed costs and variable costs. Capital cost payments, fixed operation and maintenance costs are the elements of fixed costs. Variable costs include variable operation and maintenance expenses and make-up well drilling costs. The basic scheme of the Stochastic Geothermal Cost Model (SGCM) employed in this study is presented in Figure 5. The mechanics of this model is discussed in depth in another study [7]. In this study we will employ this model to create a probability distribution of the levelized cost of a generic double-flash geothermal power plant.

Financial assumptions used in the study are presented in Table 6.

Table 6. Financial Assumptions. [8,9,10].

Project Life	30
Debt Ratio	50%
Equity Ratio	50%
Pre-tax nominal debt rate	8.00%
Debt Life	20
Inflation	2.80%
Income tax rate	41%
After tax cost of equity	16%

The input assumptions for the SGCM are presented in Table 7. The motivation for the value of the parameters where possible, is motivated by values typically appearing in geothermal energy literature. Otherwise, reasonable assumptions are made regarding the values of these parameters. We use triangular distributions to model the uncertainty of the input parameters for the ease of modeling and parameter elicitation.

Table 7. Input Parameters for the Levelized Cost Model. [8,11,12,13,14,15]

Input	Description	Unit	Uncertainty Distribution	Min	Most Likely	Max
Cexp	Exploration Cost1	$/kW	Triangular	25	127.1	309
Texp	Exploration Duration	Years	Triangular	1	2	4
Cwell	Well Cost2	MM$	Triangular	1.26	2.52	6.3
TRes	Resource Temperature	°C	Triangular	200	230	260
m_dot	Well Flow Rate	kg/s	Triangular	25	62	125
η	Turbine Conversion Efficiency	%	Triangular	80	85	95
TCond	Condenser Temperature	°C	Triangular	40	50	55
Pf	Stochastic Drilling Learning Curve Initial Parameters3	%	Triangular	50	75	85
CSF	Surface Facilities Cost4,5	$/kW	Triangular	2,202	2,581	3,009
O&M	Operation and Maintenance Cost6	¢/kWh	Triangular	1.49	2.5	5
Di	Initial Production Decline Rate7	%	Triangular	0	5	11.8
f	Plant Availability	%	Triangular	80	90	98
L	Plant Life	Years	Triangular	20	30	45

Notes:
1. Based on GEA (2005) and GeothermEx (2004). Inflation adjusted, average, minimum and maximum valuesa are used.
2. Based on Sanyal (2005), GEA (2005) and Mansure (2006). Adjusted for inflation and commodity price changes.
3. See van Dorp (2005) for the mechanics of the stochastic learning curve.
4. Based on WGA (2005) and GeothermEx (2004). Adjusted for inflation and commodity price changes.
5. Includes transmission interconnection costs.
6. Based on GEA (2005) and GeothermEx (2004). Adjusted for inflation and technology type.
7. Values are based on Sanyal (2005).

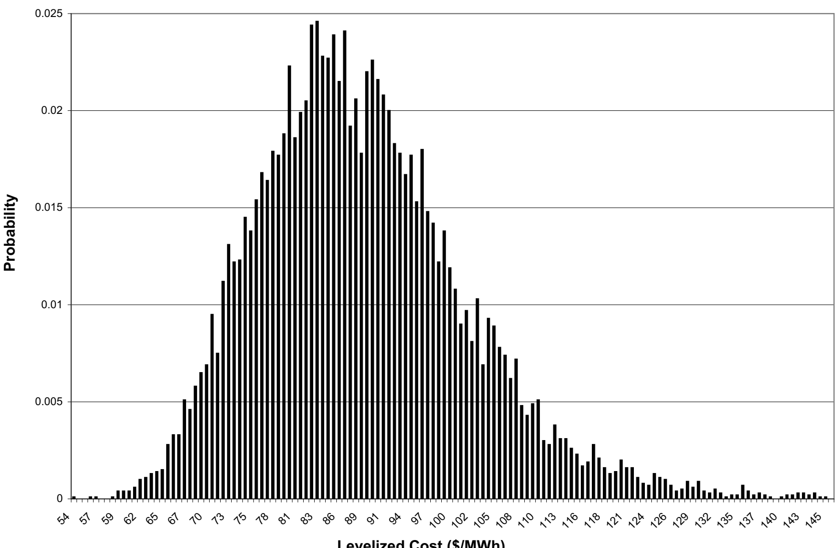

Figure 6. Levelized Cost of a Double-Flash Geothermal Power Plant – Probability Distribution Function.

We employed Monte Carlo and sampled the SGCM model shown in Figure 5 10,000 times. Resulting probability distribution function (PDF) and cumulative distribution function (CDF) of the double-flash power plant levelized cost are presented in Figure 6. Mode of the PDF is at around $83/MWh. 90% upper bound of the CDF is at $105/MWh. It can be interpreted that with 90% probability the levelized cost of a single-flash power plant will be lower than $105/MWh.

Components of the levelized cost and their 95% credibility intervals are presented in Table 8, overleaf. Capital cost, exploration, well field and surface facilities costs form 60.8% of the total cost.

The study assumes that the costs of interconnection and required transmission upgrades are included in the surface facilities cost component. However in some cases transmission upgrade costs can be a significant portion of the investment cost and have direct impact on the project's economic feasibility. We believe that a renewable energy project that requires significant investment in transmission upgrades has a minor chance to be developed. Today, transmission system related issues are one of the top discussion topics in the energy industry. Socialization of transmission costs, restructuring of the generator interconnection queue and the ability of current transmission infrastructure to handle new renewable developments are all directly related to the increasing penetration of renewables into the energy markets. Federal and state governments, regional transmission organizations, and other agencies are fully aware that in order to facilitate the development of renewable power, transmission related obstacles in front of renewable energy should be removed. Recently the Texas Public Utility Commission approved the multi billion dollar transmission expansion project that will be paid by rate payers in order to integrate the State's 18-GW wind potential into the grid [16]. This is a significant incentive (in addition to renewable energy credit and production tax credit) for the projects located in selected competitive renewable energy zones (CREZ). A similar program, the Renewable Energy Transmission Initiative (RETI) is currently in progress in California. California has substantial geothermal potential and therefore the outcomes of the RETI process are critical for geothermal development. In very rough terms the RETI process will identify the CREZ, rank them according to cost, risk and environmental factors and finally develop a transmission development strategy to provide grid

Figure 7. Levelized Cost of a Double-Flash Geothermal Power Plant – Cumulative Distribution Function.

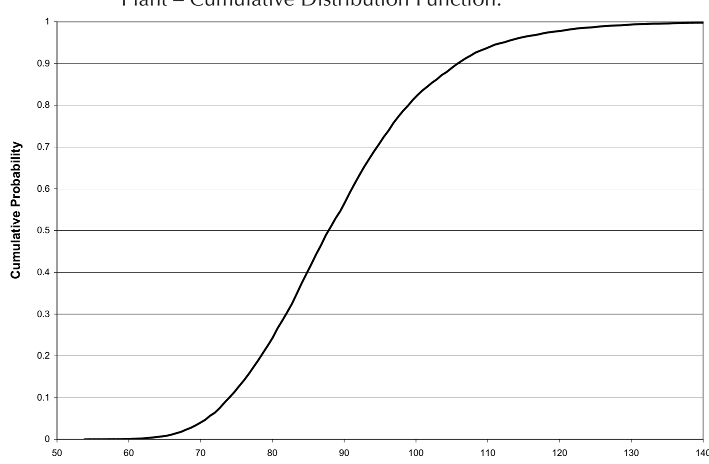

Table 8. Components of Levelized Cost For Double-Flash Cycle (2008$).

Cost Item	Lower Bound - 95% Credibility Interval ($/MWh)	Average ($/MWh)	Upper Bound - 95% Credibility Interval ($/MWh)	Average %
Exploration Cost	1.2	3.7	6.8	4.1%
Well Cost	5.6	14.9	32.5	16.8%
Surface Facilities	30.2	35.4	41.2	39.9%
O&M Costs	18	29.9	45.4	33.7%
Make-up well costs	0.7	4.9	13.9	5.5%
TOTAL	**68.0**	**88.9**	**118.4**	**100.0%**

access to selected CREZ. Once it is finalized, the transmission development plan is expected to be paid by the ratepayers [17].

6. Market Price versus Levelized Cost

In this section we compare the energy price range we developed in Section 4 with the levelized cost results from SGCM. Energy price in Figure 8 are shown with vertical lines. Derivation of the price range was explained in Table 5. Note the energy prices shown in Figure 8 does not include REC. A developer would expect levelized realized energy price to be greater than its levelized cost in order to develop the resource. Looking at levelized cost and price simultaneously price and cost seem to be overlapping for the high gas price range ($6/MMBtu-$10/MMBtu gas price region). Whereas for low gas price range ($2/MMBtu-$6/MMBtu gas price region) cost exceeds energy price. Similar comparison is shown on cumulative distribution function in Figure 9. One can find the probability of long term energy price exceeding levelized cost by looking at Figure 9. For example at $85/MWh long term energy price with 40% probability the project cost will be lower than the energy price.

Until this point we have not included the REC revenues in the energy price. The price of REC is determined by the willingness of the load serving entity to obtain renewable power and it is different for different RPS targets. For the purposes of this study let's assume that the REC is $20.4/MWh. This is the difference between average levelized cost of double-flash geothermal plant and energy price at 8,000 Btu/kWh implied heat rate and average gas price of $6.1/MMBtu (See Table 5). Figures 10 and 11 (overleaf) show the case where $20.4/MWh REC is included in plant revenues. If the REC is included the energy price becomes greater than levelized cost of a geothermal power plant in more than 50% of the cases. For example at the average historical gas price and 8,000 Btu/kWh implied heat rate realized energy price is greater than the levelized cost with approximately 55% probability. This shows the significant impact of REC on the project economics.

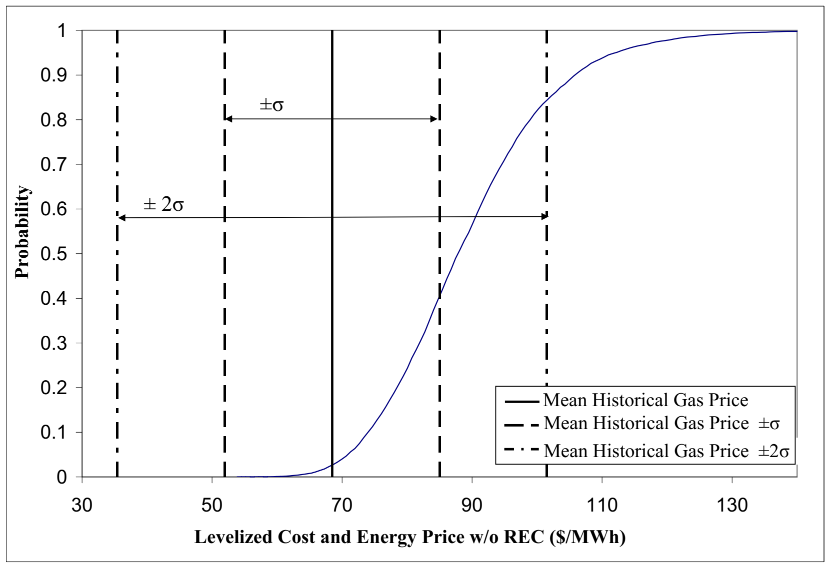

Figure 9. Comparison of Levelized Cost and Energy Price w/o REC (CDF).

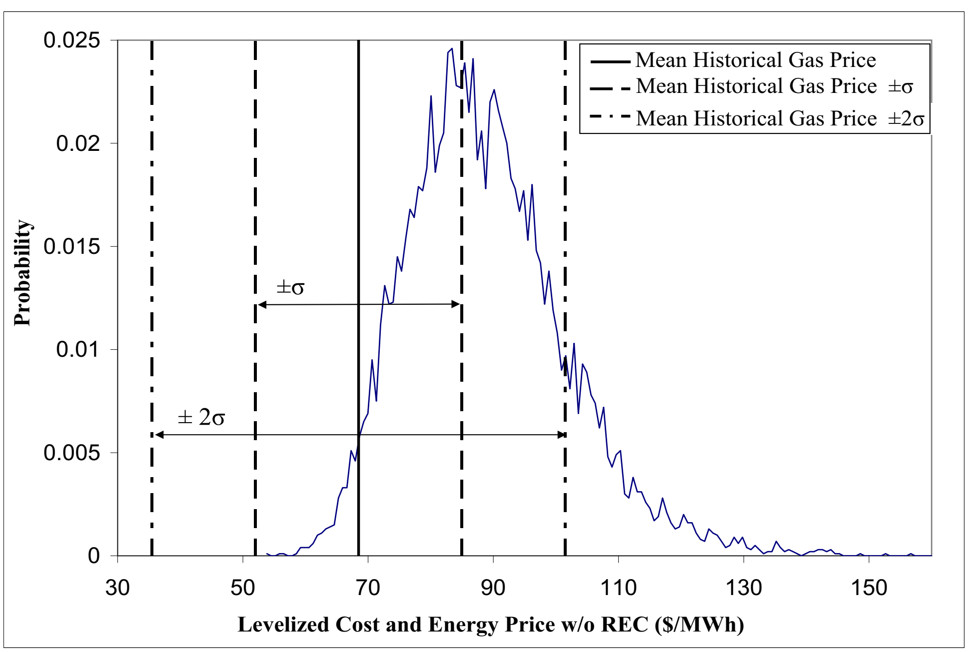

Figure 8. Comparison of Levelized Cost and Energy Price w/o REC (PDF).

7. Key Findings and Recommendations

- The supply mix of the WECC the region where a significant portion of the U.S. geothermal potential is located is dominated by gas fired units.
- Gas fired units are price setters most of the time in the region. The correlations between energy and natural gas price are strong in all major power pricing hubs.
- The development of new geothermal projects is highly correlated with the

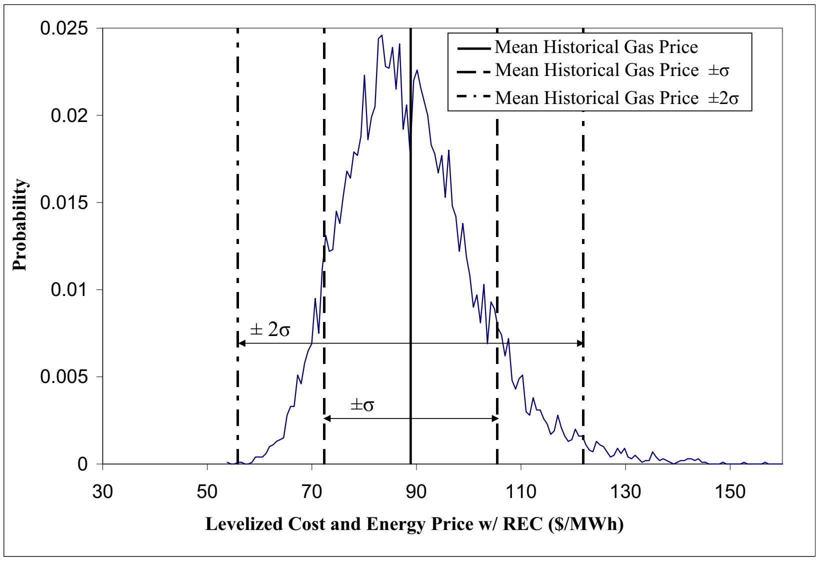

Figure 10. Comparison of Levelized Cost and Energy Price with REC (PDF).

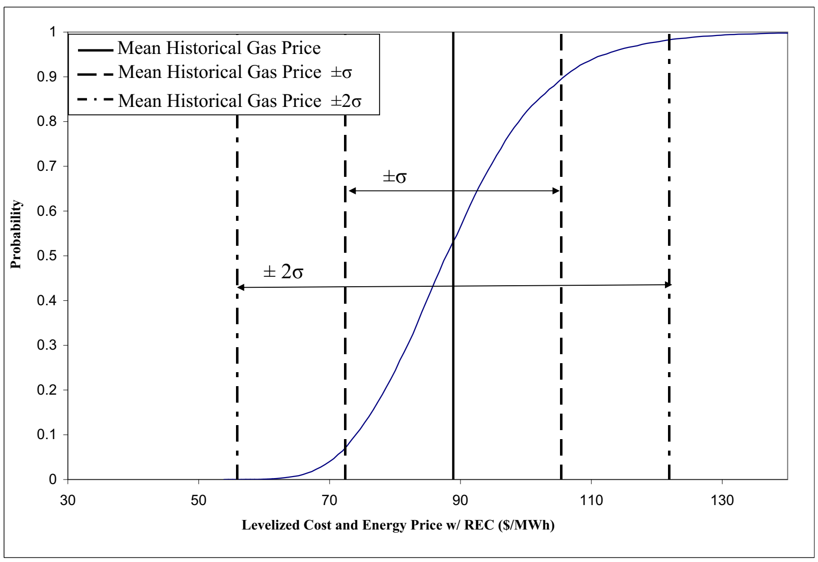

Figure 11. Comparison of Levelized Cost and Energy Price with REC (CDF).

higher gas prices. As it is shown in the Section-6 higher gas prices create more attractive investment environment for renewable developers.

- The levelized cost of a double-flash geothermal power plant ranges between $68/MWh and $118/MWh with an average of $89/MWh.

- Renewable energy credit is a critical component of geothermal power generation economics. However, REC prices are not always set by geothermal. With its 24x7 operation capability geothermal is a unique renewable energy source. Special RPS designs such as *"Geothermal Portfolio Standards (GPS)"* should be considered to increase the pace of geothermal market penetration. In our opinion establishment of GPS design is a key to facilitate the development geothermal resources. Note special RPS designs are not unheard of. For example there is currently a pending bill in Texas proposing a special RPS design to increase the diversity of the state renewable portfolio [18].

- Energy and capacity products of power plants are priced separately in major U.S. energy markets such us PJM, ISO-NE and NYISO. Other markets have also been converging towards the similar capacity market designs to increase planning reserve reliability and provide incentives for new entrants. Majority of the current RPS designs price only the energy generated by renewable sources. Put another way load serving entities pay renewable energy premium only for the energy. Planning reserve (installed capacity) contribution on the other hand is priced without making any distinction between renewable energy sources and fossil fuel fired generation. In our view the capacity product of the renewable power plants should also receive a premium on top of the market capacity price. Establishment of capacity based RPS will serve this purpose and award the renewable energy sources for their contribution to the planning reserves and therefore reliability.

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