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FEASIBILITY OF PRIVATE SECTOR'S PARTICIPATION IN GEOTHERMAL POWER GENERATION IN IRAN

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ABSTRACT

Iran wants to become an attractive frontier market for geothermal energy projects. The government has implemented laws guaranteeing power purchase for a period of up to 20 years but it seems not to be favourable enough to attract private sector participation. This is evident in the total lack of field developers since geothermal exploration begun in the Iran. The current system is not very attractive to prospective investors due to the unfavourable rate of return on their investments. This study gives an overview of the current conditions and procedural steps. It was also carried out with the aim of finding out the challenges towards Feed-in-Tariff law instrument to promote geothermal energy in Iran. To be attractive for the private sector, the price of electricity in Iran needs to increase, or drilling costs to be lowered to a comparable level to costs elsewhere in the world.

1. INTRODUCTION

Iran's energy mix is dominated by fossil fuels which satisfy around 97% of Iran's total primary energy demand (Figure 1). The remaining 3% come from a combination of hydropower, biofuels and other renewable sources as well as nuclear (BP, 2016).

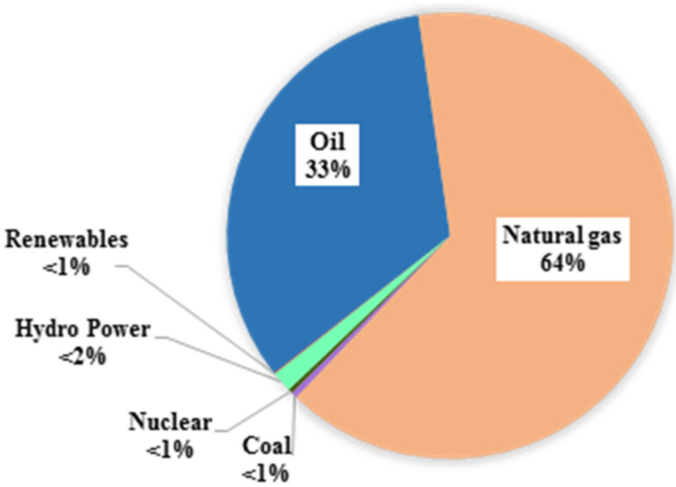

FIGURE 1: Iran's total primary energy consumption (BP, 2016)

Overreliance on fossil fuel sources is a problem for a number of reasons. For one, Iran's wealth of hydrocarbons has led the government to heavily subsidize fuel for individual energy consumption (MEI, 2016). The average price of gasoline around the world is 0.97 USD/L, while in Iran the price of gasoline is 0.39 USD/L, or close to the price of a bottle of mineral water (Globalpetrolprices.com, 2016).

Iran's average wholesale electricity tariff is 8 USD/MWh which makes the electricity tariffs in Iran among the lowest in the world compared to e.g. 75 USD/MWh in Egypt or 17 USD/MWh in Russia (TradeArabia, 2016).

Additionally, Iran spends USD 30 billion annually to fuel its thermal power plant infrastructure (MEI, 2016). Demand for electricity is increasing in Iran, as the population is growing 3.5% faster than the country's GDP (gross domestic product). These numbers underline that Iran cannot reasonably sustain the use of hydrocarbons to generate electricity nationwide (MEI, 2016).

Iran will experience two major benefits by transitioning to a more diverse energy mix. First, a reduced domestic demand for fossil fuels will lead to increased competitiveness in global energy markets. In other words, reduced domestic demand will allow Iran to export more of its immense reserves of oil and natural gas to client states abroad. Second, reducing domestic fuel use will allow the government to ease its costly subsidies while simultaneously meeting a growing electrical demand through more sustainable and cost effective renewable energy sources (MEI, 2016).

The Iranian government is considering paying more attention to the utilization of renewable energies. Among the renewable sources, Iran has geothermal energy potential. The exploitable potential of geothermal energy for electricity generation is estimated to be 5,000-6,000 MW (Energypedia, 2016). Iran has also begun development on the Middle East's first geothermal power plant. This "pilot" station in the northwest Iranian province of Ardabil is expected to have an installed capacity of 50 MW (MEI, 2016).

To increase incentives for investing in renewable energy, Iran amended its laws in 2015. The previous regulations provided for a period of only five years a power purchase agreement including a uniform tariff for all types of technology. Pursuant to the new laws, a new system of feed-in tariffs, differentiating prices by type of technology, has been implemented. Moreover, the guaranteed period for power purchase has been extended to 20 years (WFW, 2016).

The present policy seems not to be favourable enough to attract private sector participation. This is evident in the total lack of field developers since geothermal exploration began in the Iran. The current fiscal incentives being enjoyed by these developers are not sufficient to warrant continuous sustainable exploration and development of this resource. The present system is not attractive to prospective investors, basically due to the unfavourable rate of return on their investments. To hasten the exploration and development of our geothermal resources, we need to improve the regulation to attract investments.

2. PRIVATE PARTICIPATION IN GEOTHERMAL ELECTRICITY GENERATION

2.1 Review of government regulations in Iran

2.1.1 Statistics of non-governmental renewable power plants

In Iran, the first non-governmental power plant became operational in 2009. Since 2009 until now, more than 440 million kWh of electricity from renewable sources have been produced and fed to the grid. The price of the electricity equalling 1270 billion Rials was paid to the power plants (SUNA, 2016). Table 1 shows the share of each renewable energy source in the generation of electricity.

TABLE 1: Summary of information related to production of non-governmental renewable power plants (SUNA, 2016)

	Wind (MWh)	**Solar (MWh)**	**Biomass (MWh)**	**Small hydro (MWh)**	**Sea (wave) (MWh)**	**Geothermal (MWh)**	**Total (MWh)**
Production	390,425	712	44,734	4,633	---	---	440,506

Until April 2016, of the received requests and issued permits for construction of non-governmental renewable energy power plants, about 68 MW were in production (Table 2) and 565 MW had obtained a power purchase agreement, based on two types of buyback contracts (3 MW) and a 133-article contract or guaranteed purchase (562 MW) (SUNA, 2016). As mentioned before, there is no non-governmental geothermal power plants in Iran (Table 1).

TABLE 2: Summary of information related to permits given to non-governmental renewable power plants (SUNA, 2016)

	Wind (MW)	**Solar (MW)**	**Biomass (MW)**	**Small hydro (MW)**	**Sea (wave) (MW)**	**Geothermal (MW)**	**Total (MW)**
Capacity	53.88	0.514	13.56	0.44	---	---	68.394

2.1.2 Feed-in tariffs

On the implementation of the legal obligations of Ministry of Energy, the guaranteed electricity purchase tariff for types of renewable are as follows (Table 3):

TABLE 3: The guaranteed electricity purchase tariff for the first 10 years for renewable energy (SUNA, 2016)

Technology type		**Guaranteed purchase tariff (IRRs/kWh)**	**Guaranteed purchase tariff (US¢/kWh)**
Biomass	Landfill	2700	9
	The anaerobic digestion of manure, sewage and agriculture	3500	11
	Incineration and waste gas storage	3700	12
Wind farm	> 50 MW capacity	3400	11
	≤ 50 MW capacity	4200	13
Solar farm	> 30 MW capacity	3200	10
	≤ 30 MW capacity	4000	13
	≤ 10 MW capacity	4900	16
Geothermal (including exploration and equipment)		4900	16
Waste recycling in industrial processes		2900	9
Small hydropower (≤ 10 MW capacity)	Installation in rivers, and through use of dams	2100	7
	Installation through pipelines	1500	5

Power Purchase Agreements of power plants subject to this announcement are extended to a 20 years' period with the specified tariffs. Tariffs will be multiplied by a factor of 0.7 after adjustment of Article 3 of the *Economic Council Directive* starting from the first day of the second 10 year period until the end of the contract. The rates of this announcement are applied to contracts, where the contracted power plant has been constructed and commercially operated within a period of a maximum of 30 months since the notification of the contract. Tariffs will be proportionately increased up to 30% in accordance to the instructions under Article 6 of the *Economic Council Directive*, for power plants constructed using local equipment, technologies, know-how, design and manufacturing (SUNA, 2016).

2.1.3 Procedural steps

Workflow for a proposed project should be as follows (Figure 2):

Phase 1: Registration and issuance of construction permit.
Phase 2: Obtaining required permits and concluding contract.
Phase 3: Project execution period and construction of the power plant (after signing the contract).

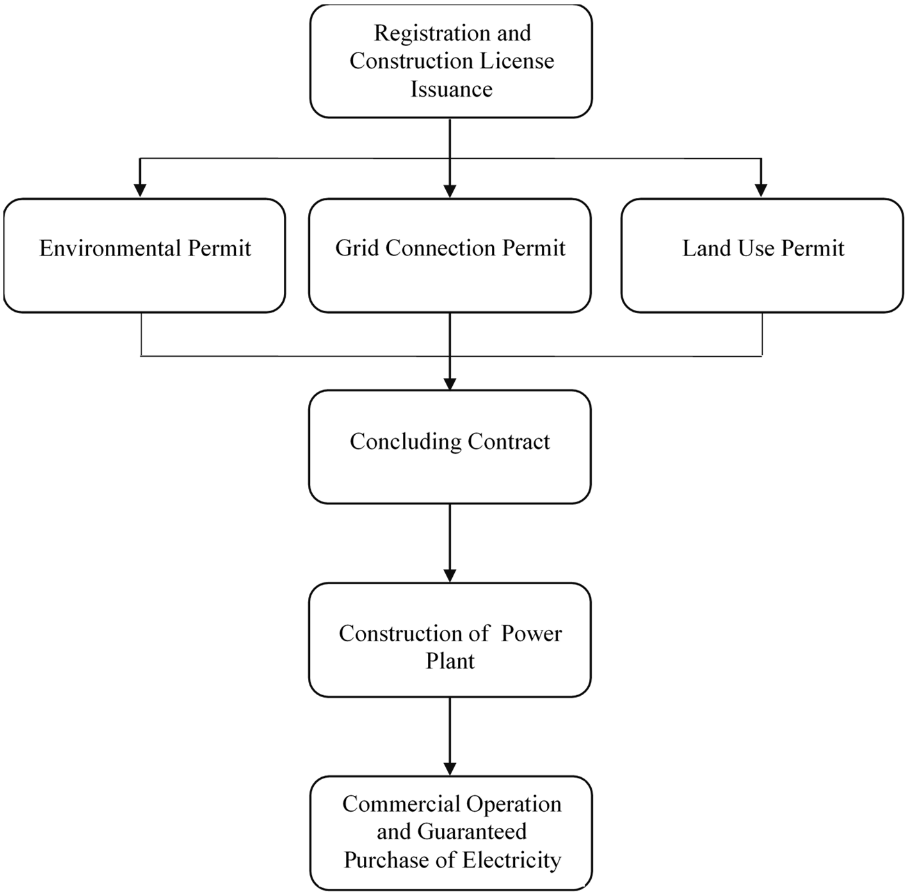

FIGURE 2: Steps of implementing renewable energy projects (SUNA, 2016)

Phase 4: Operating period.
In order to start constructing a renewable energy power plant in Iran, an application must be submitted to SUNA (Renewable Energy Organization of Iran) containing details of the project such as location and estimated capacity of the plant. The applicant must be non-governmental. Moreover, it must be an Iranian person, thus, foreign investors are required to incorporate a company in Iran (or to enter into a joint venture with a local partner). However, it is permissible for foreign investors to hold 100% of the share capital in an Iranian company. Upon verification of the aforementioned requirements and on the condition that no overlap exists with the sites of previously registered projects, SUNA will issue a construction permit to the applicant.

Following the issuance of the construction permit, the applicant has to obtain other necessary permits such as environmental preservation, grid connection and land permits. Thereafter, a power purchase agreement can be concluded with SUNA and the construction of the power plant can commence. During the construction period, the project company is required to periodically submit progress reports to SUNA. SUNA controls and supervises the construction and coordinates the grid connection tests and inspections through the Iran Grid Management Company. The plant must be commissioned within 18 months of the conclusion of the power purchase agreement, otherwise the tariff valid at the time of commissioning will be applied, rather than the tariff valid at the time of the conclusion of the power purchase agreement (WFW, 2016).

2.2 Review of governmental regulations in other countries

Countries worldwide are increasingly turning to *feed-in tariffs* as a mechanism to develop geothermal energy. In many countries of the world feed-in tariffs play a fundamental role in raising the commercial interest of investors in geothermal electricity production such as in Austria, Croatia, Ecuador, France, Germany, Greece, Indonesia, Italy, Japan, Kenya, Moldova, Portugal, Serbia, Slovakia, Slovenia, Switzerland, Taiwan, Turkey, and Uganda (Table 4).

TABLE 4: The guaranteed electricity purchase tariff for geothermal energy in selected countries

Country	Size of plant	Contract term	US¢ / kWh
Austria [1]	-	13	8.29 (reduced by 1% annually)
Ecuador [2]	-	15	13.81
France [1]	-	15	French mainland: 22.31 + premium of up to 8.92 for energy efficiency Overseas Departments and Overseas Collectives): 14.5 + premium of up to 3.35 for energy efficiency
Germany [1]	-	20	28.11
Greece [1]	-	20	Low-temperature geothermal generation: 15.951 (no support); 14.501 (with support) High-temperature geothermal generation (>90°C): 12.27 (no support); 11.155 (with support)
Indonesia [3]	-	-	I. Sumatera, Java and Bali, Sulawesi, NTB, NTT (11.8-15.9) (2015-2025) (0.4 average increase/year) II. Halmahera, Maluku, Papua and Kalimantan (17-23.3) (2015-2025) (0.6 average increase/year) III. Isolated areas within Region I and II where electricity is supplied by fuel oil power plant (25.4-29.6) (2015-2025) (0.4 average increase/year)
Italy [1]	1 kW - 1 MW	20	15.059
Japan [4]	< 15 MW ≥ 15 MW	15	38 25
Kenya [5]	35-70 MW	20	8.8-20% for first 12 years and 15% after
Moldova [1]	-	15	Feed-in tariffs are determined and approved annually, depending on type and capacity of power plant, amount of electricity produced and expected to be delivered.
Portugal [1]	≤ 3 MW	12	The indicative average rate is 30.117
Serbia [1]	≤ 1 MW 1-2 MW > 5 MW	12	10.79 11.58-0.77×P; where P = installed power 7.72
Slovakia [1]	-	15	17.304
Slovenia [1]	-	15	The price is based on the reference price applicable on the day on which the contract is concluded.
Switzerland[1]	≤ 5 MW ≤ 10 MW ≤ 20 MW > 20 MW	20	41 37 29 23
Taiwan [7]	-	20	15.9081
Turkey [1]		10 years for feed-in tariff, first 5 years of operation for bonus tariff for local-content support	10.5 local-content bonus: 0.7-2.7
Uganda [6]		20	7.7

Sources: 1) Res-Legal, 2016; 2) Campen and O'Sullivan, 2015; 3) Repit.wordpress, 2016; 4) IEA, 2016; 5) ERC, 2016; 6) ERA, 2014; 7) MOEABOE, 2015 and 2016.

In selected countries, the contract terms of feed-in tariffs for electricity generated from geothermal power are valid from 12 to 20 years. The tariffs vary significantly between countries, from 7.7 US¢ in Uganda to 41 US¢ for small geothermal power plants in Switzerland. Japan, Serbia and Switzerland have more than one tariff category, depending on the size of the power plant (Haraldsson, 2014).

3. COST ESTIMATION OF BUILDING A GEOTHERMAL POWER PLANT

3.1 Capital cost of a geothermal power plant

The primary stages of a geothermal developmental cycle are exploration, resource confirmation, drilling and reservoir development, plant construction and power production. Four phases of the geothermal energy project will be used as a baseline plan for a future feasibility models:

1) Exploration and confirmation cost;
2) Drilling cost;
3) Power plant cost;
4) Operation and maintenance cost.

The capital cost of geothermal power plants varies, depending on the resource chemistry, temperature, and technology employed. The majority of the overall cost is typically attributed to construction of the power plant, due to the high cost of raw materials including steel (46.6% of the total cost). The second highest costs are associated with the exploration and production drilling stages, which together can comprise 42% of the total cost. Low-temperature reservoirs typically use binary power plants, while moderate- to high-temperature reservoirs employ dry steam or flash steam plants, based on whether the production wells produce primarily steam or water, respectively (Cross and Freeman, 2008). Table 5 shows capital costs of a geothermal power plant according to different references. This information indicates that capital costs of binary projects are higher than those of flash technologies.

TABLE 5: Overview of some reported capital cost of geothermal power technologies

Author	Technology	Capital cost (USD/W)	Cap. cost range (USD/W)
Geo-energy, 2016	NS (not specified)	3.4	-
Chatenay and Jóhannesson, 2014	NS (50 MW uses 250°C geothermal fluid)	3.7	-
Gehringer and Loksha, 2012	NS	4	-
Salmon et al., 2011	NS	3 - 4	-
Konyali, 2010	NS	1.2 – 3	-
Average capital cost not specified (NS)		**3.33**	**1.15 - 4**
Matek and Gawell, 2014	Flash	2.7	-
IRENA, 2012	Flash	2 - 4	-
Average capital cost flash		**2.83**	**2 - 4**
Matek and Gawell, 2014	Binary	5.2	-
IRENA, 2014	Binary	5 - 10	-
Chatenay and Jóhannesson, 2014	Binary (10 MW using 150°C geothermal fluid)	5.3	-
IRENA, 2012	Binary	2.4 - 5.9	-
Average capital cost binary		**5.53**	**2.4 - 10**

3.1.1 Exploration and confirmation cost

Exploration is the initial development phase and seeks to locate a geothermal resource that can provide sufficient energy to run a power plant and produce electricity. This phase begins with various kinds of exploration methods and field analysis, and ends with the drilling of the first successful full-size commercial production well. Resources defined during the exploration phase, can be divided into three sub-phases: regional reconnaissance, district exploration, and prospect evaluation. Recent interviews with geothermal developers provided exploration cost estimates averaging 150 USD/kW. Total exploration cost figures may thus range from 100 to 200 USD/kW according to the nature of the project (greenfield vs. expansion), the amount of information available initially, the selection of technologies involved in each exploration phase, and the size of the project and resulting economies of scale (Hance, 2005).

The confirmation phase includes the drilling of additional production wells and testing their flow rates until approximately 25% of the resource capacity needed by the project is achieved. It also involves reservoir design, engineering, and the drilling of some injection capacity to dispose of fluids from production well tests. Other activities and costs consist of well testing, reporting, regulatory compliance and permitting, and administration. Confirmation cost estimates for commercially viable projects are considered to average 150 USD/kW (Hance, 2005). An average cost of 346 USD/kW can be considered when the confirmation phase is done in tandem with the exploration phase (Salas, 2012). In this study, exploration and confirmation cost is considered 346 USD/kW.

3.1.2 Drilling cost

Exploration cost related to drilling is usually the single largest cost and a highly risky component in any geothermal development. Given the circumstances, it is expected that the cost of drilling will be very variable; while this is certainly true to some degree, there are general tendencies (Salas, 2012).

Two major factors will affect the total drilling costs:

1) The cost of drilling individual wells; and
2) The number of wells to drill.

The cost of an individual well is mainly related to the depth and diameter of the well as well as the properties of the rock formation. The number of wells to drill is determined by the average well productivity and the size of the project. Well productivity directly depends on the resource temperature and the rock permeability (Hance, 2005).

The productivity of each well (P_{well}) expressed as a function of estimated reservoir temperature (T_{well}) can be written as:

$$P_{well} = \frac{9}{250}\, T_{well} - 2.86 \tag{1}$$

Additional wells are drilled for production purpose. One reinjection well is usually required for every 4-5 production wells (Ngugi, 2013).

For estimation presented here, based on information from industrial partners, it is assumed that the average depth of the wells in Sabalan area is 2,400 m and the estimated reservoir temperature is 265°C. In addition, drilling cost in Iran is 5,000 USD/m, while it is not so high in other countries as will be better discussed in Section 5.2. Most fields have an overall success rate of over 50% and 80-90% is the most common (Avato, 2013). For the study presented in this report, the success rate is assumed to be 75%.

3.1.3 Power plant cost

Equipment purchase cost estimation is the key driver of the capital cost estimation for a given power plant project. There are three main sources of equipment estimation data: vendor contacts, open literature, and computerized estimating systems (Salas, 2012). In this section, the prices of the main geothermal power plant components are collected from home country purchase documents for the 5 MW Sabalan geothermal pilot plant.

There is an important concept to take into account when estimating costs: economy of scale. Economy of scale refers to the idea that "bigger is cheaper" per unit output. In quantitative terms (Geirdal, 2013):

$$\left(\frac{C_i}{K_i}\right) = \left(\frac{C_0}{K_0}\right)\left(\frac{K_i}{K_0}\right)^{n-1} \tag{2}$$

where C_i = The cost of the unit of size i;
C_0 = The cost of the reference unit;
K_i = The size or rating of unit i;
K_0 = The size or rating of the reference unit;
n = The scale exponent.

Scale exponent is often about 0.6 for chemical processing plants. In general, n has a range of 0.5 to 0.9, for different types of equipment and each type of processing plant has its characteristic value (Berthouex, 1972). In this study, economy of scale is used for estimating the cost of a 50 MW power plant and n is assumed 0.9.

3.2 Operation and maintenance costs

The operation and maintenance cost (O&M cost) factors may be categorized as ordinary O&M costs which include staff, administrative and cost of spares, the plant inefficiency, reservoir management costs and cost of capital associated with increased working capital.

The rate of operation and maintenance is fairly low for geothermal power plants in comparison to conventional power plants. The Kenyan experience indicates the cost to be about 0.00763 USD/kWh (Ngugi, 2012). According to ESMAP, total O&M costs for a 50 MW power plant in a developing or developed country would be in the range of USD 3.5-10.5 million per year. These costs can be translated into USD 0.009-0.027 per generated kWh, based on a 90% capacity factor (Gehringer and Loksha, 2012). For this estimation, it is assumed 0.009 USD/kWh.

4. FINANCIAL FEASIBILITY ASSESSMENTS

Before an investment decision is made it is necessary to determine whether or not the planned investment idea is feasible. A financial feasibility analysis is an effective analytical tool which can be used to evaluate investments from various perspectives, such as technical, social, legal, financial, market, and organizational (Björnsdóttir, 2010).

The finances necessary to make an investment must be paid right away, while benefits accrue over time. Benefits are based on future events and the ability to predict the future is imperfect; therefore, it is crucial to carefully evaluate investment alternatives (Salas, 2012).

For investors to engage in a new investment project, the project has to be financially viable. Invested capital must show the potential to generate an economic return to investors at least equal to that available from other similarly risky investments, i.e. the return on investment needs to be equal or higher. Financial feasibility analysis is an analytical tool used to evaluate the economic viability of an investment. It consists of evaluating the financial conditions and operating performance of the investment and forecasting its future conditions and performance. A financial decision is dependent on two specific factors, expected return and expected risk, and a financial feasibility analysis is a means for examining these two factors (Björnsdóttir, 2010).

The model used in this study is a mathematical model which makes it easier and less time consuming to update the analysis. It is designed for Microsoft Excel in a spreadsheet form. In this model the Net Present Value (NPV) and Internal Rate of Return (IRR) are used as profitability criteria. Both of them are calculated with Excel's built-in functions. Two scenarios will be calculated for profitability in order to figure out the viability of this project:

- *Scenario 1*: 5 MW geothermal power plant
- *Scenario 2*: 50 MW geothermal power plant

4.1 Net Present Value

The Net Present Value (NPV) is the difference between the present value of all cash inflows and cash outflows associated with an investment project. The formula for the NPV is (Björnsdóttir, 2010):

$$NPV(i) = \frac{A_0}{(1+i)^0} + \frac{A_1}{(1+i)^1} + \cdots + \frac{A_N}{(1+i)^N} = \sum_{n=0}^{N} \frac{A_n}{(1+i)^n} \tag{3}$$

where A_n = Net cash flow at the end of period n;
i = MARR (Marginal Attractive Rate of Return);
N = Service life of the project.

If the NPV(i) is positive for a single project, the project is financially feasible, since a positive NPV means that the project has greater equivalent value of inflows than outflows and therefore makes a profit (Björnsdóttir, 2010).

The calculation of the NPV requires a value for the discount rate i and its selection is the main difficulty for this method. Discount rate value selection is essentially a strategic function and is done from the viewpoint of the entire organization. The value of the discount rate that is used can be the financial cost of capital, the economic cost of capital or the risk adjusted discount rate (Salas, 2012).

4.2 Internal Rate of Return

The Internal Rate of Return (IRR or i*) is defined as the compound rate of return i that makes the NPV equal to zero (Salas, 2012) which is expressed as:

$$NPV(i^*) = \sum_{n=0}^{N} \frac{A_n}{(1+i^*)^n} = 0 \tag{4}$$

Investors usually want to do better than breaking even in their investments. Their investment policy usually defines a minimum acceptable rate of return (MARR), in which case the IRR and the MARR can be used to decide whether a project is feasible or not. The decision rule for a simple project is as follows (Björnsdóttir, 2010):

If *IRR* > *MARR*, accept the project;
If *IRR* = *MARR*, remain indifferent;
If *IRR* < *MARR*, reject the project.

4.3 Model inputs and assumptions

As with any model calculations, some assumptions regarding the model have to be made. The assumptions made for the financial model are stated here below.

The planning horizon is the amount of time an organization will look into the future when preparing a strategic plan and is set to 20 years in this study based on the contract terms of the feed-in tariffs. The construction time of the power plant is assumed to be one year (2016) for Scenario 1 and seven years for Scenario 2 (2016-2022).

Capital cost. The total cost in this model is divided into three categories: buildings costs, equipment costs and other costs.

Working capital is the capital needed to pay short-term debts and continue operations. It is assumed to be 0 MUSD for Scenario 1 and 36 MUSD for Scenario 2.

Financials. The financial inputs and assumptions include requirements of the owners, tax and accounting regulations of the respective country, etc. (Björnsdóttir, 2010). Following are the required inputs regarding the project's financials which are based on Iran's laws and regulations (see Table 6):

- *MARR*: the minimum acceptable rate of return for both project and equity needs to be determined by the project owners.
- *Equity percentage*: the part of the project's capital cost that will be paid with equity from owners. The financing for both scenarios in this project is considered to be 25% equity and 75% loan.
- *Dividend percentage*: the proportion of profits that will be paid to owners in the form of dividends.
- *Income (corporation) tax*: determined in compliance with the respective country's laws and regulations.
- *Depreciation*: determined in compliance with the respective country's laws and regulations. Depreciation categories may have to be defined as applicable for each project, e.g. buildings, equipment and other investment.
- *Loan interests*: different interests are available for different projects, depending on the project's estimated return and risk, as well as conditions on financial markets. If the project owners plan to refinance the project after some time, the refinancing interests also need to be determined.
- *Loan life*: the time from when repayments of a loan start until the loan is fully paid.

TABLE 6: Financials inputs

Input	Value
Discounting rate project, MARR project	17%
Discounting rate equity, MARR equity	24%
Equity	25%
Loans	75%
Loan repayments	5 years
Loan interest	6%
Debtors	10%
Creditors	10%
Dividend	30%
Depreciation buildings	4%
Depreciation equipment.	10%
Depreciation other	20%
Loan management fees	2%
Income tax	25%

5. RESULTS

5.1 Financial feasibility assessments in Iran – capital cost

The previous sections provided a methodology to estimate all expenses related to the capital cost for development of a geothermal power plant (PP). Capital cost for geothermal power plant includes exploration and confirmation, drilling and power plant costs. Most of the estimations are based on related literature, which present average cost figures. Table 7 shows a summary of costs for the two different PPs, 5 MW and 50 MW. The estimated capital costs will be used as input in the financial modelling. Figure 3 illustrates the breakdown of the total capital cost for the two scenarios. This includes

TABLE 7: Estimated cost of the two different geothermal power plant

Power plant capacity (MW)	Category	Cost (MUSD)
5	Exploration and confirmation	1.7
	Drilling	12
	Power plant	15.7
	Capital cost	29.5
	Capital cost per MW	5.9
	Operation and maintenance (every year)	0.4
50	Exploration and confirmation	17.3
	Drilling	144
	Power plant	124.9
	Capital cost	286.2
	Capital cost per MW	5.7
	Operation and maintenance (every year)	3.9

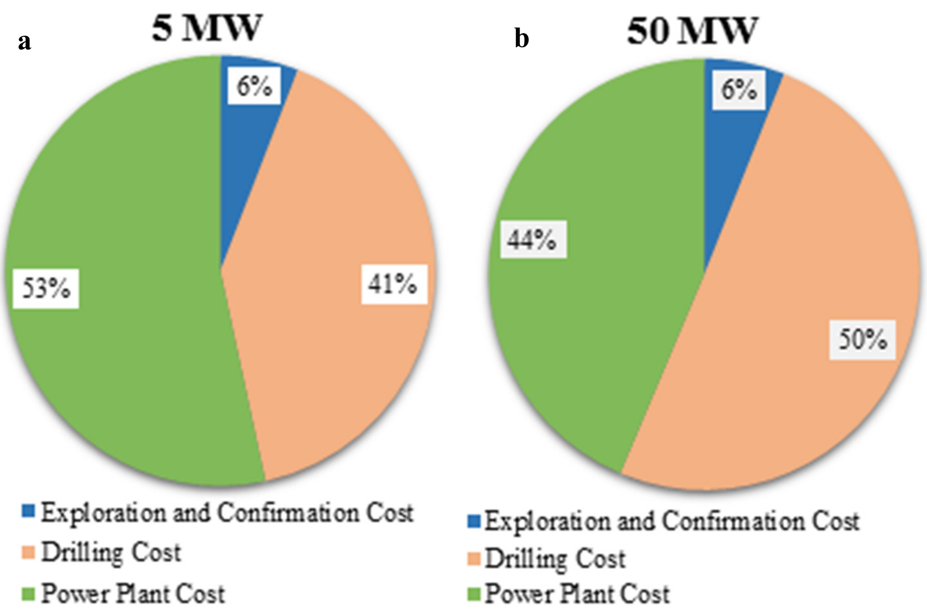

FIGURE 3: Breakdown of the total capital cost for, a) a 5 MW PP; and b) a 50 MW PP

all the costs associated with total investment where the drilling cost is approximately 50%. In the case of Iran drilling cost is the dominant factor. The bigger power plant is more cost effective, so the share of the power plant cost (percentage wise) for the 50 MW PP is lower than for the 5 MW PP. Therefore the share of the drilling costs (percentage of the total costs) for the 50 MW PP will be bigger than for 5 MW.

5.1.1 Scenario 1 - 5 MW geothermal power plant

The cash flows of the investment project for the 5 MW power plant are illustrated in Figure 4. The chart shows two cash flows, one for capital investment and the other for equity. As seen from the chart, there is outflow of cash during the construction of the project, i.e. in the first year (2016). When the construction is finished, the project starts to generate income but just for one year (2017) because after a year the loan received must be paid. The loan received, which accounts for 75% of the investment cost and working capital, is paid over 5 years after a year of start-up in 2018, so this is the reason why there is a dip in the net cash flow and equity from 2018 to 2022. After that the power plant begins to make profit as revenues from sales. Tariffs will be multiplied by 0.7 from the first day of the second 10 years

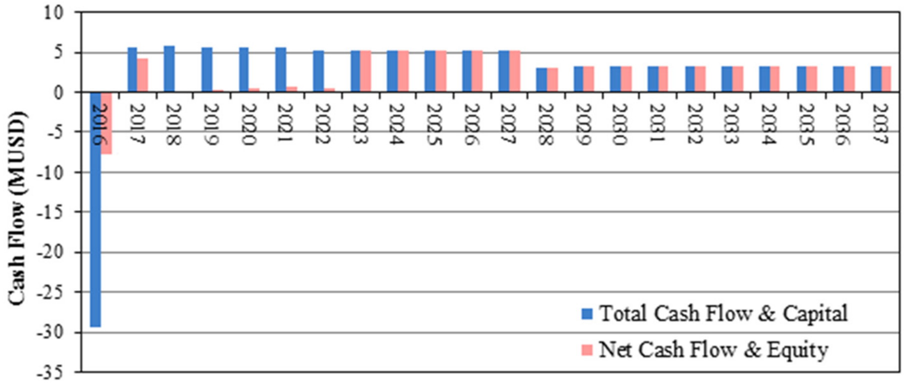

FIGURE 4: The cash flows of the project for a 5 MW PP

period until the end of the contract which explains the dip in net cash flow and equity from 2027 to 2028.

Figure 5 shows the accumulated NPV over the planning horizon. The NPV of net cash flow becomes positive over the planning horizon but the NPV of the total cash flow increases over the planning horizon without ever becoming positive. Since the NPV of total cash flow is zero the project remains balanced. The necessary payback period to recover investments is higher for the project (end of year contract) than for the equity investors but still payback period for the equity is high (10 years after operation began).

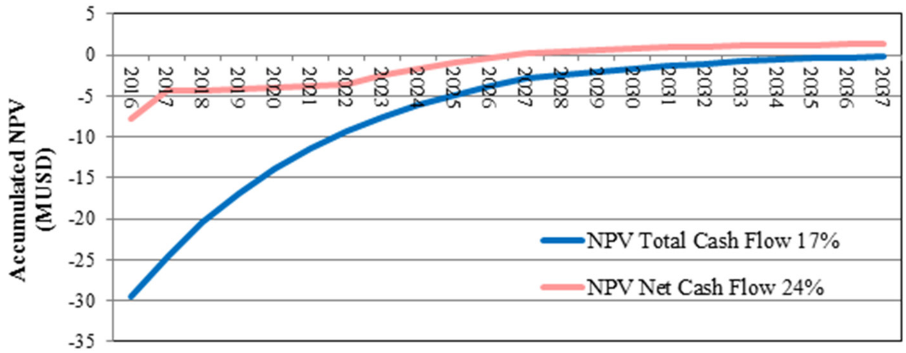

FIGURE 5: Accumulated NPV over the planning horizon for a 5 MW PP

The IRR is of much interest to the investors. Figure 6 shows how the IRR rises throughout the planning horizon for the 5 MW PP. The MARR for Net Cash Flow is 24% and the MARR for Total Cash Flow is 17%, see Table 6. Since the IRR of Net Cash Flow is higher than the MARR (or the discount rate), this project can be considered a profitable project for the equity investors but since the IRR of the total

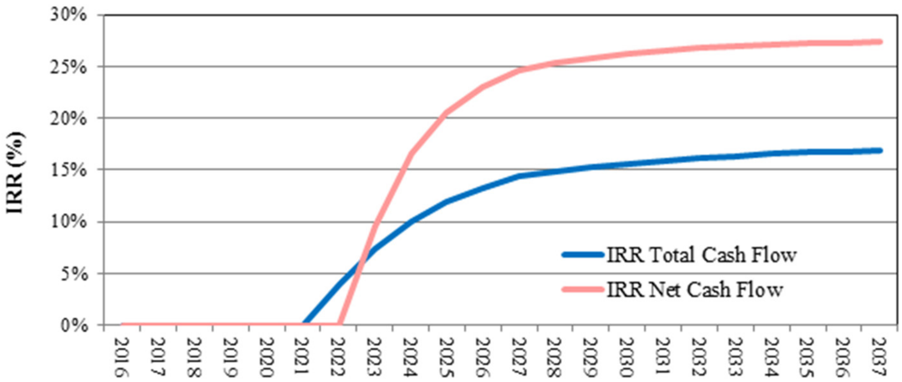

FIGURE 6: Internal Rate of Return for 5 MW

Cash Flow equals the discount rate, the project remains balanced. By comparing Figure 5 and Figure 6 it can be seen that the NPV of net cash flow reaches zero at the same time as the IRR reaches the MARR.

Both cash flow ratios and financial ratios for the 5 MW PP show that based on these results there is not much foundation for investment and the project remains balanced.

5.1.2 Scenario 2 - 50 MW geothermal power plant

The cash flows of the investment project for a 50 MW PP are illustrated in Figure 7. The chart shows two cash flows, one for capital investment and the other for equity. As seen from the chart, there is outflow of cash during the construction of the project, i.e. in the first seven years (2016 - 2022).

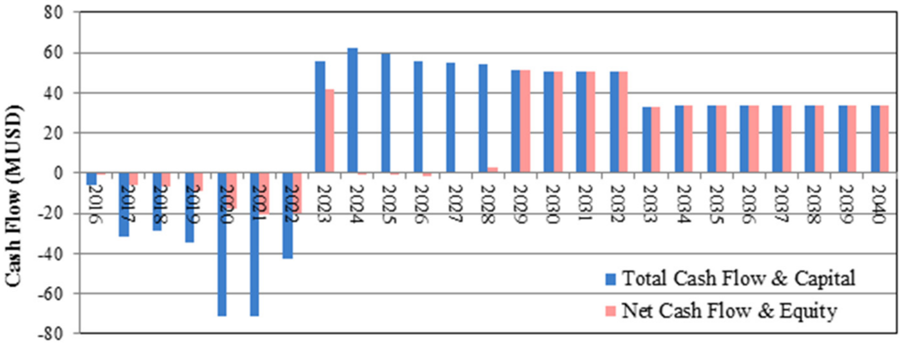

FIGURE 7: The cash flows of the project for a 50 MW PP

The loan received, which accounts for 75% of the investment cost and working capital, is paid back over a period of 5 years, starting a year after the start-up in 2024, which is the reason why there is a dip in the net cash flow and equity from 2024 to 2028. When the construction is finished, the project starts to generate income but just for one year (2023) until the received loan must be paid. The project does not generate net profits from 2024 until 2026 and due to the accumulated losses the project is still in the red numbers at the end of the planning horizon. Tariffs will be multiplied by 0.7 from the first day of the second 10 years until the end of the contract which shows the dip in net cash flow and equity from 2032 to 2033.

Figure 8 shows the accumulated NPV of the project over the planning horizon. The graph shows how the project increases its NPV over the planning horizon without ever becoming positive. At the end of this period the NPV of total capital is -48 MUSD and NPV of equity is -12 MUSD.

The IRR is of much interest to the investors. Figure 9 shows how the IRR rises throughout the planning horizon for a 50 MW PP. The IRR for Net Cash Flow is 18% and the IRR for Total Cash Flow is 12%.

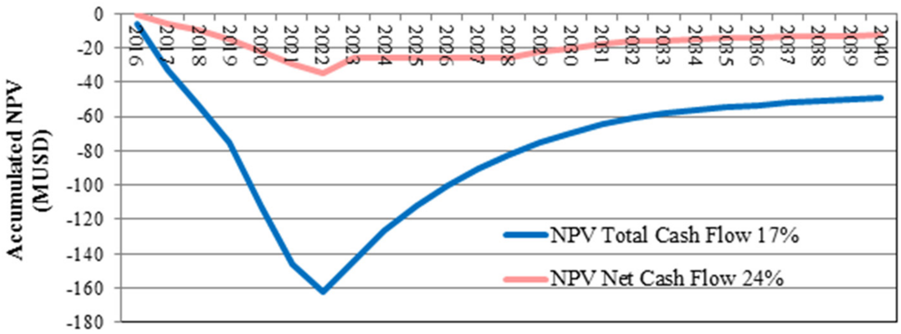

FIGURE 8: Accumulated NPV over the planning horizon for a 50 MW PP

Since the IRR of Total Cash Flow and Net Cash Flow are lower than the discount rate (for equity and total capital they are 24% and 17%, respectively), this project cannot be considered a profitable project.

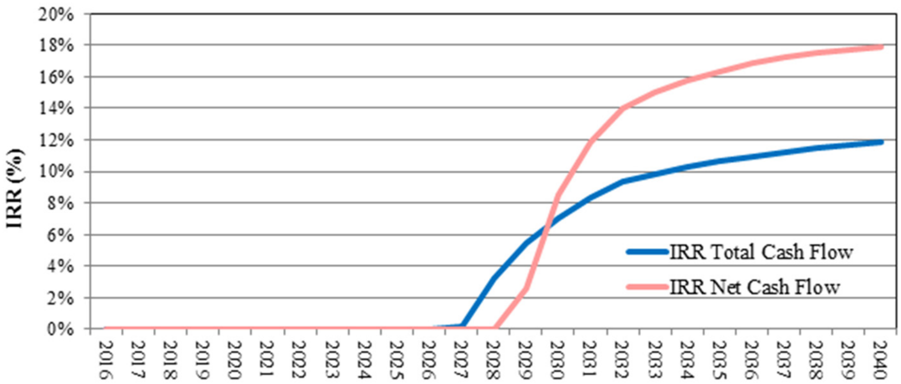

FIGURE 9: Internal rate of return for a 50 MW PP

Both cash flow ratios and financial ratios for a 50 MW PP show that based on these results there is not much foundation for investment. The ratios are all lower than the present acceptable minima and therefore the project would have difficulties meeting its obligations with regard to repayment of loans and other financial obligations.

5.2 Comparing financial feasibility study in Iran with other countries

Drilling costs in the Middle East are more expensive because the demands are very high compared to other countries and the competition with the oil and gas industry. Drilling cost in Iran is around 5000 USD/m, while this cost is not as high in other countries. Based on information from industrial partners, the drilling cost in other countries is estimated around 1300-3500 USD/m. This is the reason why the geothermal power plant construction is too expensive in Iran. In addition to drilling costs, some financial parameters are also different which affect the results. For example, discount rates for projects and equity are 10% in some countries while in Iran these are higher. Also loan repayments time in Iran is only 5 years while in some countries it can be more than 10 years.

Given the current situation, our present system is not very attractive to prospective investors - leading to favourable rate of return on their investments. To hasten the exploration and development of our geothermal resources, Iran needs to provide an environment that will attract investments, with proposed legislative measure offering a package of incentives, both in fiscal and contractual arrangements.

5.3 Sensitivity analysis

The most effective way to present the results of a sensitivity analysis is plotting sensitivity graphs. All variables are then plotted on the same graph, each as a separate line. The slopes of the lines show how sensitive the output is to a change in each variable; the steeper the slope is the more sensitive is the outcome to a change in a particular variable. It is therefore very good for the decision maker to take the results of the sensitivity analysis into account in the decision-making process, and if possible arrange to mitigate risk associated with changes in key parameters (Björnsdóttir, 2010).

Figure 10 shows a sensitivity graph for Scenario 2 (50 MW PP). Input parameters that are known to have most effect on the outcome of a geothermal project were selected for the analysis. As seen from the graph, the IRR of this project is most sensitive to changes in electricity price and buildings costs, which includes drilling cost. These parameters affect the outcome in a different way, as an increase in the electricity price increases the IRR, but an increase in drilling cost decreases the IRR.

As seen from the sensitivity analysis in Figure 10, small changes in input values can affect the outcome of the analysis significantly. If the electricity price or drilling costs change, the project can become profitable. The sensitivity analysis in Figure 10 for the electricity price and drilling costs shows that a relatively modest increase in the price of electricity or decrease in drilling costs can change the financial aspect of the project. If the price of electricity can be raised from the current 16 US¢/kWh to 24 US¢/kWh (1.5 times) or if the drilling costs can be decreased from 5000 to 1600 USD/m, the economics of the project can change significantly. Tables 8 and 9 show a summary of a sensitivity analysis of this project. The result of the calculation are shown in Appendix I.

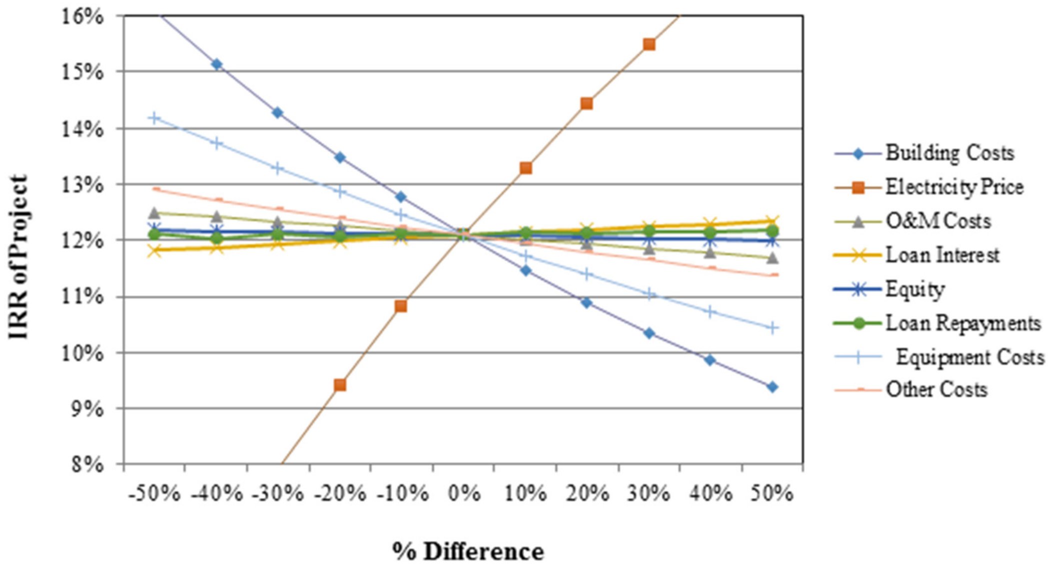

FIGURE 10: Sensitivity graph for a case study for a 50 MW PP

TABLE 8: Summary of a sensitivity analysis for a 50 MW PP when the electricity price is changed

Electricity price (US¢/kWh)	NPV Total Cash Flow (MUSD)	NPV Net Cash Flow (MUSD)	IRR Total Cash Flow	IRR Net Cash Flow
16	-48	-12	12%	18%
24	6	16	18%	31%

TABLE 9: Summary of a sensitivity analysis for a 50 MW PP when the drilling cost is changed

Drilling cost (USD/m)	NPV Total Cash Flow (MUSD)	NPV Net Cash Flow (MUSD)	IRR Total Cash Flow	IRR Net Cash Flow
5000	-48	-12	12%	18%
1600	4	13	18%	34%

Loan repayment is also important for the financial analysis, therefore it is assumed that the government gives loan for renewable energy projects with a longer repayment period (for example 10 years). But this will not affect the result much.

As mentioned in previous sections, the MARR for Net Cash Flow is 24% and the MARR for Total Cash Flow is 17%. Since the IRR of Total Cash Flow and Net Cash Flow after changing the price of electricity or drilling cost are higher than the discount rate, this project can now be considered profitable with an energy price of at least 24 US¢/kWh, or with drilling costs not exceeding 1600 USD/m.

6. CONCLUSIONS

Based on the abundant resources of geothermal, Iran should be attractive for geothermal business. The government has implemented laws guaranteeing power purchase for a period of up to 20 years but it does not seem to be favourable enough to attract private sector participation. Financing the initial investment is the main barrier. The main goal of this study was to find out whether or not there is a financial foundation for the private sector's participation in geothermal power generation in Iran.

The conclusion of this study is that geothermal power development projects in Iran are not very attractive for private investors when the potential investor takes into consideration the costs of exploration and confirmation, drilling into an unknown field, and running a power plant with the current electricity tariffs.
The profitability model came up with an indifferent result for Scenario 1 (a 5 MW geothermal PP) and an infeasible result for Scenario 2 (a 50 MW geothermal PP). Risk analysis suggests that the most important financial factors that affect the project profitability are the energy price and the drilling costs.

In order for the scenarios to be successful in the real world the price of electricity in Iran would have to increase at least 1.5 times to 24 US¢/ kWh or drilling costs have to be lowered to a comparative level to costs elsewhere in the world. This means they would have to decrease at least to 1600 USD/m. It can also be added, that bigger power plants can be more economic since the highest value of the scale exponent was selected for scaling.

These are some problems which could be solved with the will and determination of the Iranian government. Important factors where the government could help to generate a positive impact on profitability and risk of the investment are: energy price, taxes and reduction of drilling costs. Numerous alternatives could be evaluated such as: improved tax incentive laws, large period energy contracts, public funds for exploration and confirmation phases, and different scenarios like:

1) Geothermal reservoir exploration by private developers;
2) Drilling for steam and hot water production by private developers;
3) Buying steam and water and generating electricity through private developers;
4) Drilling for steam and hot water production and generating electricity through private developers.

The decision-making process for large projects is very complicated and obviously, all aspects could not be covered in this paper. Many assumptions were also made, some based on little available information.

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APPENDIX I: Results of a sensitivity analysis based on 24 US¢/kWh electricity price

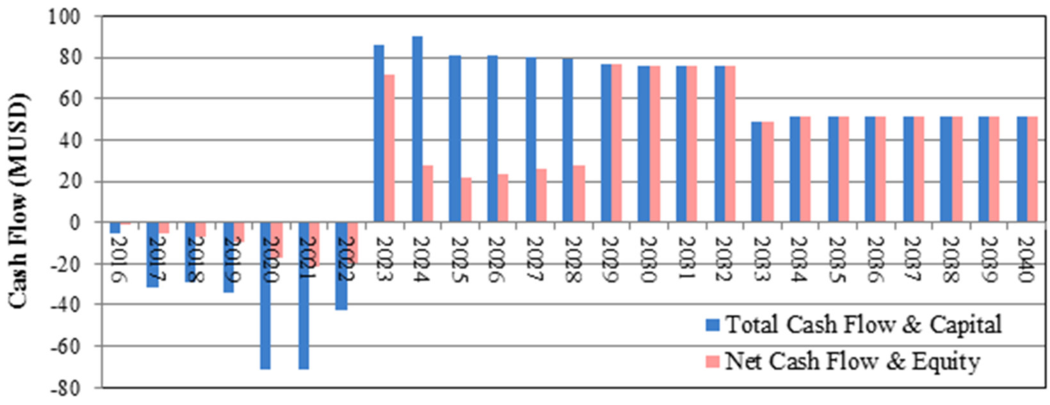

FIGURE 1: The cash flows of the project for a 50 MW PP with 24 US¢/kWh electricity price

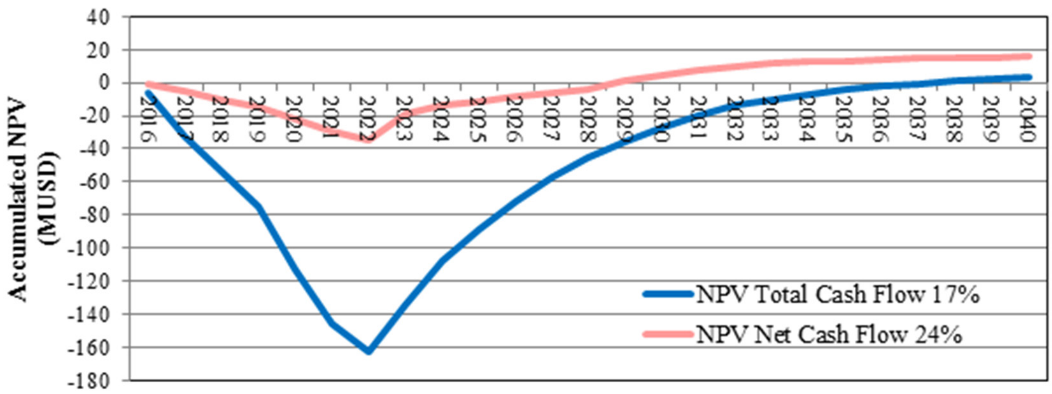

FIGURE 2: Accumulated NPV over the planning horizon for a 50 MW PP with 24 US¢/kWh electricity price

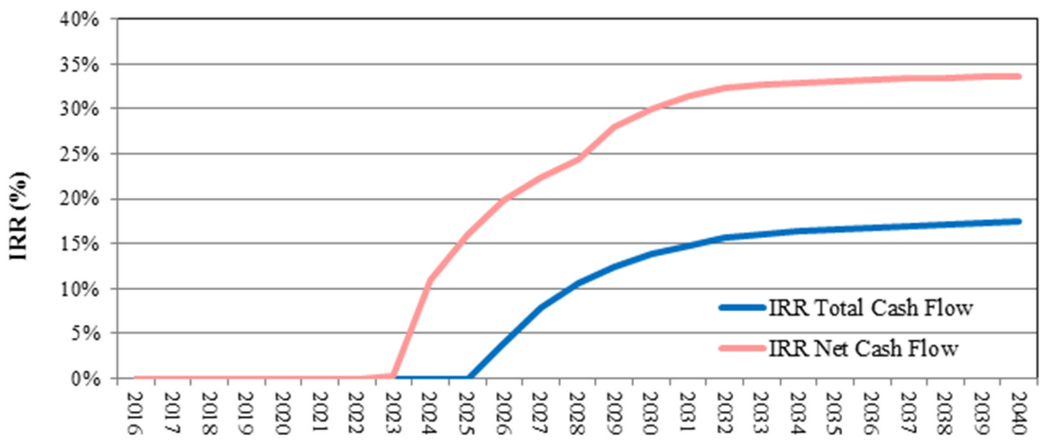

FIGURE 3: Internal Rate of Return for 50MW with 24 US¢/kWh electricity price

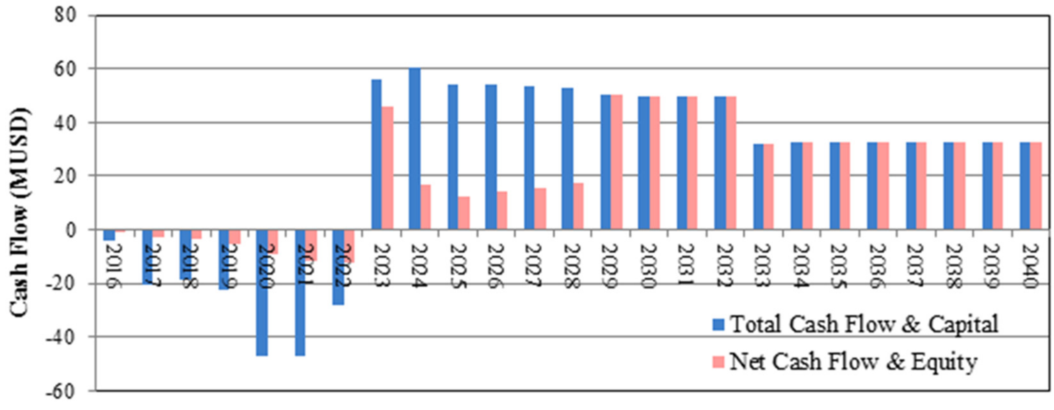

FIGURE 4: The cash flow of the project for a 50 MW PP with 1600 USD/m in drilling costs

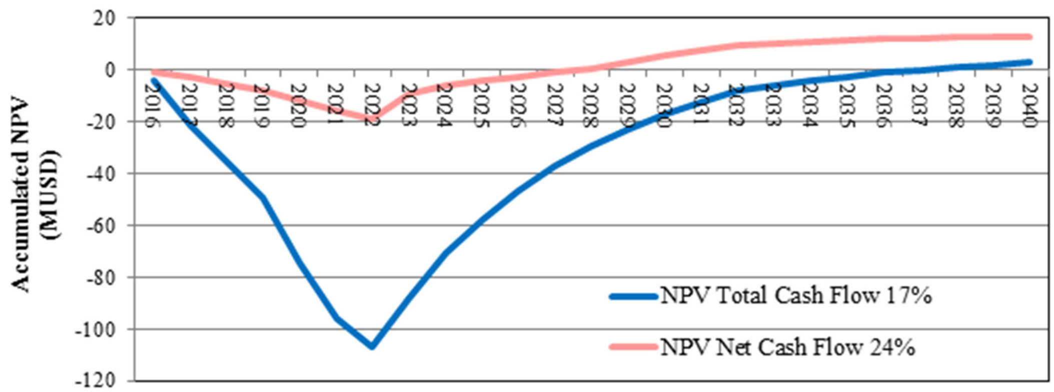

FIGURE 5: Accumulated NPV over the planning horizon for a 50 MW PP with 1600 USD/m in drilling costs

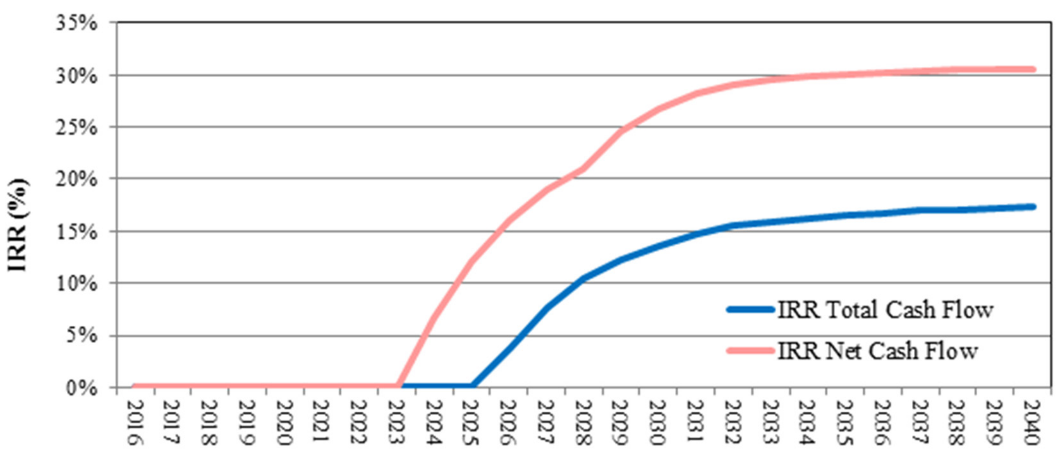

FIGURE 6: Internal Rate of Return for a 50 MW PP with 1600 USD/m in drilling costs