TECHNO-ECONOMIC ESTIMATION OF THE GEOTHERMAL POTENTIAL OF EXISTING COLOMBIAN OILFIELD PRODUCTION WELLS

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ABSTRACT

Using co-produced hot water from oil and gas wells and binary power plant technology for power generation purposes has been piloted in oilfields worldwide with profitable results. In Colombia these geothermal resources associated with oilfields are available with geothermal gradients up to 65°C/km. Oil and gas producers have expressed interest in technologies that enable decarbonization of oilfield operations. With this in mind, the development of this type of project could be economically and environmentally beneficial.

This work analyses data from oil and gas wells in Colombian oilfields to evaluate the feasibility of implementing a binary plant using the available co-produced water. The numerical calculations included economic and thermodynamic analysis of Organic Rankine Cycle (ORC) specifications for different working fluids and geothermal fluid supply temperatures. It was determined that *n*-pentane is the most appropriate working fluid at the conditions of 90°C brine supply temperature and 27°C ambient temperature. This finding is supported by industrial realities, but it is notable that it is not impacted by high ambient temperatures. Economic analysis showed a levelised cost of energy of 55 USD/MWh with a 7-year payback time.

This work supports proposed geothermal development in Colombia. Small scale, low risk, profitable projects like this can catalyse the industry and spur development.

1. INTRODUCTION

1.1 Geothermal Energy in Colombia

Colombia is a country with a high geothermal energy potential. The Colombian geological survey identified 15 areas of geothermal exploration interest related to igneous and volcanic bodies located in the North Andean Block, mostly along the central, western, and eastern cordilleras. The information from temperature logs from oil wells has revealed additional regions with high geothermal gradients up to 65°C/km, associated with sedimentary basins. These areas are located in the Llanos basin, Caguan-Putumayo basin, and the Magdalena Valley (Aguilera Bustos *et al.*, 2019).

The Colombian geological survey concluded that about 7% of the installed power generation capacity could be replaced by using geothermal resources (Alfaro & Rodríguez-Rodríguez, 2020). This equates to 2210 MW and 1340 MW using high and low enthalpy resources, respectively.

1.2 Geothermal Development in Colombia

Geothermal exploration in Colombia has been studied since 1968 (CHEC, 1968; CHEC & ICEL, 1983; OLADE *et al.*, 1982), especially in convective systems associated with volcanic areas located in the Colombian Andes ridge. Currently most of these areas are well characterised and preliminary conceptual models suggest a great potential for power generation (Aguilera Bustos *et al.*, 2019).

Two power generation projects are planned in the coming years. The first one is located in the most studied geothermal area of Colombia called Valle de Nereidas, Nevado del Ruiz, which is a convective system that foresees a 65 MWe installed capacity power plant. The second is the installation of 5 MWe from low-temperature geothermal water in a conductive system located in a sedimentary basin in one of the oilfields operated by Colombian oil company Ecopetrol (Alfaro & Rodríguez-Rodríguez, 2020). These projects have been impeded by legal and institutional issues, delaying their development (Moreno-Rendón *et al.*, 2020).

1.3 Electricity Generation from Co-Produced Separated Water

In a mature oilfield the produced fluid can contain up to 98% water (Vajpayee et al., 2016). The first step in processing is to separate this water from the valuable hydrocarbons. Historically, the co-produced water has been seen as an inconvenience in oilfields since it generally requires costly disposal due to its impurities, instead being reinjected to improve well productivity but increase the water content in the reservoir over time. Recently this by-product has been identified as a resource for potential electricity generation (Wang *et al.*, 2018). The existing impurities are less significant than those seen in traditional geothermal power development and will likely not hinder development (Vajpayee et al., 2016). In the case of Colombian oilfields, average temperatures reported for this co-produced water are in the range of 75 ºC to 90 ºC (Cuadrado Peña *et al.*, 2015; Quintero, 2019).

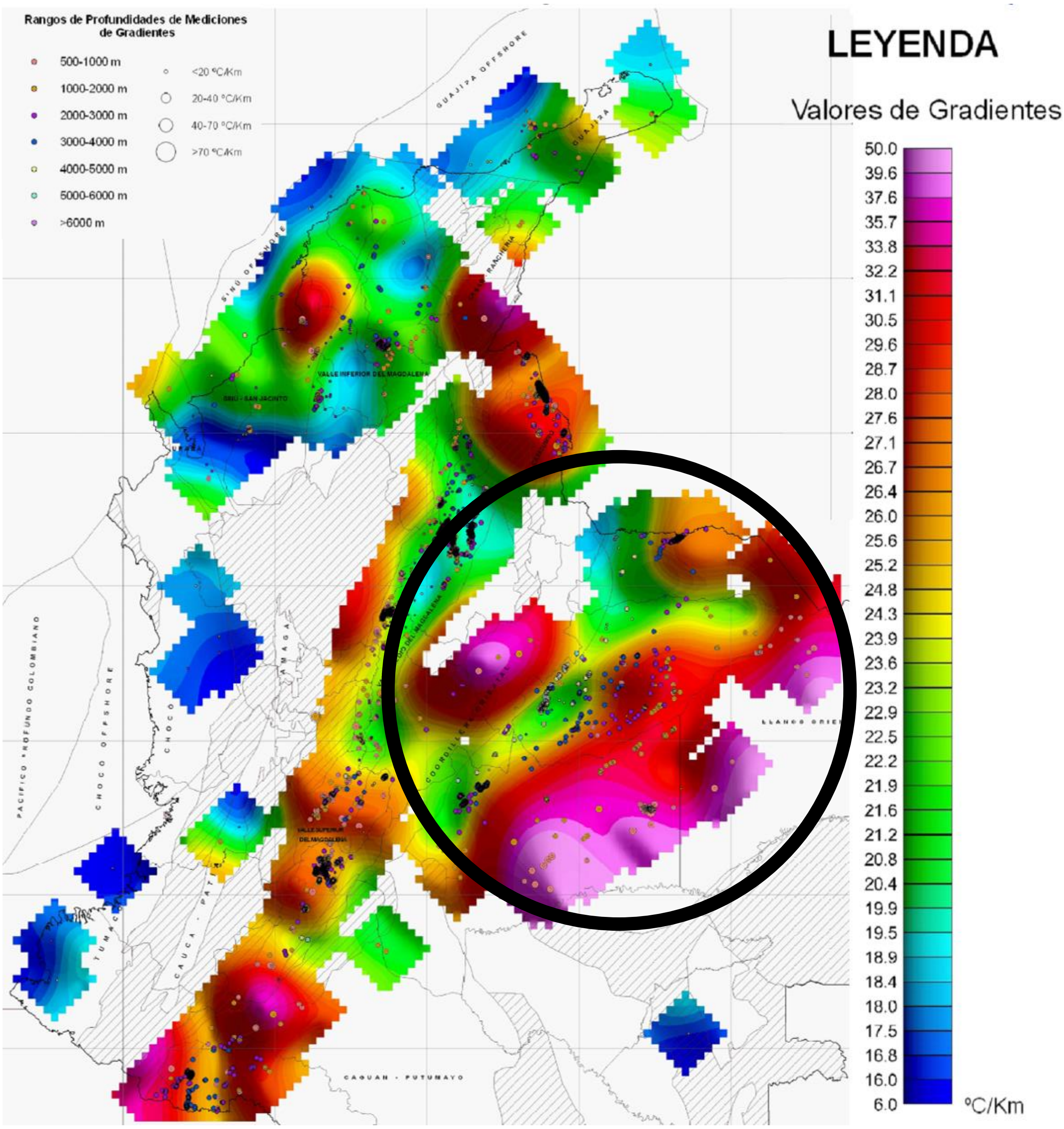

Figure 1. Map of geothermal gradient in Colombia, determined using bottomhole temperature measurements. Modified from: (Alfaro *et al.*, 2009). Circle represents area of interest.

Generating power from oilfields is a relatively new application of ORC technology, as seen from Table 1. The only significant differences between this and other projects is the composition of the geothermal fluid and the co-production nature of the operation. The composition of the fluid is higher in hydrocarbons than other fluids and lower in dissolved minerals. This is actually a benefit as without the threat of silica scaling reinjection temperatures can be very low and the lack of other minerals means equipment cleaning will be less critical. As this fluid is already being produced, the nature of the designed operation is different, there is no risk or uncertainty about the flowrates and temperatures of the fluid and the largest capital expense (drilling the well) is already in place.

Table 1. Table of electricity generation projects from oilfield co-produced water.

Location	Water temperature / °C	Net power generation / kW	Reference
Wyoming, USA	90.6	132	(Nordquist & Johnson, 2012)
North Dakota, USA	98	250	(Gosnold, 2015)
Huabei, China	110	310	(Xin *et al.*, 2012)

At present, the electricity sector in Colombia is dominated by hydro-power, accounting for 83% of the total generation, with thermal as an back-up and intermittency buffer (ACOLGEN, 2021). For this reason, geothermal power is less effective in decarbonising the electricity grid than it would be with other countries. The benefit of utilizing co-produced water is that generation of power on oilfields is currently met using diesel generators. Connecting remote oilfields with electrical grids is expensive and the cost of power can be prohibitive, generating consistent power on-site is an ideal situation for a process that values resiliency and reliability. These favourable conditions make this a suitable demonstration project to catalyse further geothermal developments in the country.

1.4 Organic Rankine Cycle

An Organic Rankine Cycle is a method of generating power using a thermodynamic cycle. It utilizes a heat source to vaporise a working fluid (typically an organic compound, hence the name) which is used to spin a turbine generating electricity. Exhaust from the turbine is condensed using a heat sink, with condensed liquid being repressurised and returned to the vaporiser. In a geothermal ORC, hot geothermal fluid (gas or liquid) is used as a heat source and air is used as a heat sink. In this arrangement the working fluid operates between these two temperatures, evaporating near the heat source temperature and condensing above the heat sink temperature. As is expected, the difference between these two temperatures is a significant factor in the design and efficiency of a geothermal ORC.

Geothermal ORCs have been successfully deployed in many countries, with 1193 MW installed worldwide in 2014 (Bertani, 2016). These systems are typically installed in conjunction with or separate to traditional flash or dry steam geothermal power plants. The standardised design is a shell and tube heat exchanger acting as the vaporiser, a turbine, an air-cooled finned tube condenser and various other shell and tube heat exchangers in-between, increasing efficiency depending on the fluid and design. This design is seen diagrammatically in Figure 2.

The working fluid chosen is crucial to the design of the ORC. This is typically chosen by balancing the heat source and sink temperatures with other factors including: price, global warming potential, ozone depletion potential, atmospheric lifetime, working pressure and flammability. A critical feature of a working fluid is its thermodynamic properties, most importantly the condition of the fluid exiting the turbine (superheated vapour or partially condensed).

1.5 Economics

Clearly the benefits of situating an ORC on an existing oilfield and utilizing separated water as the heat source are significant. The drawbacks however are the low flow rate and low temperatures. This means an economic assessment is still necessary to assess the potential of this technology, especially in a country without any installed examples of such a plant. To analyse the economics of this project several metrics will be used, these are detailed below,

- Net Present Value (NPV)
  This metric adjusts immediate and future investments and revenue to account for the time value of money.
- Levelised Cost of Energy (LCOE)
  This metric compares the revenue from electricity production over a plant's lifespan with capital costs incorporating the time value of money.
- Weighted Average Cost of Capital (WACC)
  This value is the sum of the cost of debt and the cost of equity, calculated as a weighted average.
- Capital Asset Pricing Model (CAPM)
  This calculates the company/project/investor required rate of return.

Economic conditions in Colombia also affect the economic viability of a project - most notably these are an exemption from the VAT (19%) and import duties when developing non-conventional energy sources. These incentives are enabled by law 1715 of 2014 and National Development Plan 2018-2022 of Colombia (Estrada, 2015).

2. METHODOLOGY

2.1 Geothermal conditions

The data collected regarding the co-produced water average temperature was obtained reports in the open literature (Cuadrado Peña *et al.*, 2015; Quintero, 2019) and from one of the Colombian oilfields operated by the company Ecopetrol.

2.2 ORC Conditions

A variety of working fluids were considered in this work including *iso*-butane (iC4), *n*-butane (nC4), *iso*-pentane (iC5), *n*-pentane (nC5), R134a, R245fa, ammonia and toluene. The ORC studied was simulated using HYSYS V12 (Aspentech, 2021). The generalized design is shown in Figure 2.

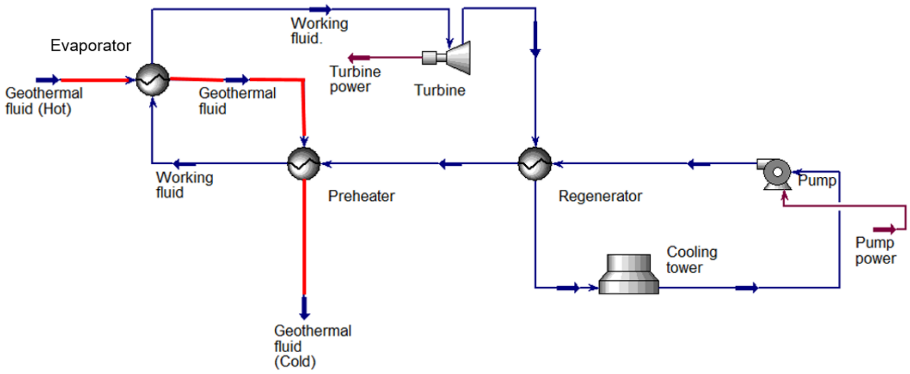

Figure 2. Diagram of ORC simulation model.

This model has several simplifying assumptions as listed below:

- Frictional pressure losses are ignored
- Turbine performance is set at 75% isentropic efficiency
- Ambient temperature is constant at 27°C and the condenser cools the working fluid to 35°C
- Condenser takes a vapour superheated by 2°C and returns a liquid subcooled by 2°C
- Evaporator takes a subcooled liquid by 5°C and produces a vapour superheated by 2°C
- The regenerator was excluded for wet/isenthalpic working fluids

In general, the system is optimized for each working fluid and brine inlet temperature. The system is optimized with respect to minimizing geothermal fluid flowrate as the gross power is set. Calculated parameters for each point include:

- Energy efficiency (1st law)

$$\eta_I = \frac{Net\ power\ produced}{Energy\ supplied\ through\ brine} = \frac{W_{turbine} - W_{pump} - W_{Condenser}}{\dot{m}C_p(T_{in} - T_{out})}$$

- Energy efficiency (2nd law)

$$\eta_{II} = \frac{Net\ power\ produced}{Energy\ supplied\ through\ brine} = \frac{W_{turbine} - W_{pump} - W_{Condenser}}{\dot{m}C_p(T_{in} - T_{out})(1 - T_{ambient}/T_{in})}$$

- Heat exchanger area (evaporator) – using the calculated UA and a set heat transfer coefficient of 1600 W/m²K.

2.3 Economics

The economic feasibility was analysed by calculating financial parameters such as Net Present Value (NPV), the Internal Rate of Return (IRR) and the Weighted Average Cost of Capital (WACC). Then, a sensitivity analysis was carried out with different ratios of equity and debt to compare the outcomes.

Capital cost estimation was based on a 100 kWe (gross) capacity plant from a supplier, including piping, civil and electrical works. The cost of the working fluid was not included since it is negligible compared with the total system costs (Song *et al.*, 2020). Using this capital cost, economic factors will be calculated using a 30-year lifespan with a 90% capacity factor. Various other factors specific to Colombia are incorporated including corporate tax rates and inflation (Central Bank of Colombia, 2021). A detailed list of assumptions is provided in the Appendix.

3. RESULTS

3.1 Technical

For each working fluid studied and at each brine supply temperature the optimal working pressure (pressure in the evaporator) was determined by minimizing the geothermal fluid flowrate required to generate 100 kWe (gross). To demonstrate this minimization an example of determining the minimum geothermal fluid flowrate is shown in Figure 3. Here brine is supplied at 90°C, *n*-pentane is used as a working fluid and the evaporator pressure varied from 150 – 360 kPa.

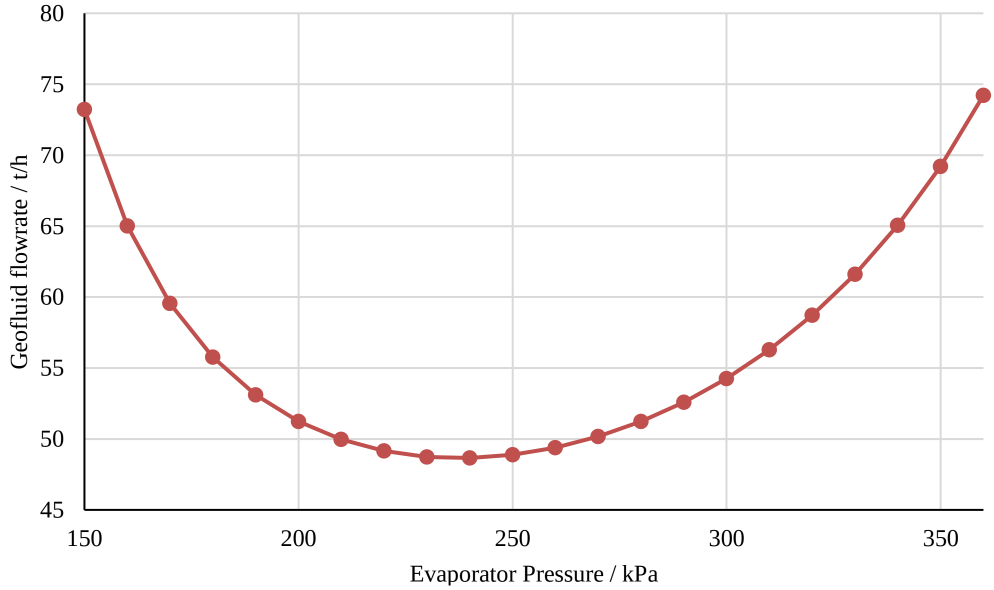

Figure 3. Graph of geothermal fluid flowrates required to generate 100 kWe gross for various evaporator pressures.

Figure 3 shows that at approximately 240 kPa, the flowrate of geothermal fluid is at a minimum. This pressure is equivalent to a saturated vapour temperature of 64°C. Also of interest are the temperature of the spent brine and the working fluid flowrate required, these variables are plotted against the saturated vapour temperature of the evaporator in Figure 4.

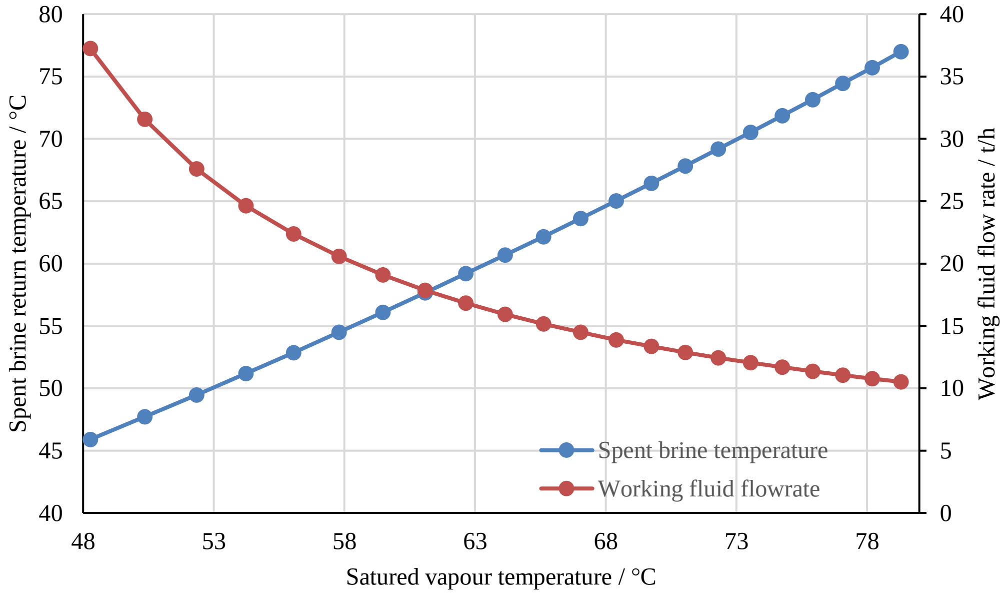

Figure 4. Graph of spent brine return temperature and working fluid flowrate required to generate 100 kWe (gross) at a variety of working fluid conditions.

Figure 4 shows that as evaporator pressure increases (and saturated vapour temperature increases accordingly) the return temperature of the geothermal brine increases significantly. Intuitively this makes sense as a higher average temperature in the evaporator means less heat is able to be extracted from each tonne of brine. In many cases this would be considered losing efficiency, but here the return temperature of the brine is irrelevant - the relevant metric is geothermal fluid flowrate at a fixed gross electricity production rate. Similarly working fluid flowrate decreases as evaporator pressure increases. This is expected as a higher evaporator pressure means more work can be extracted from each tonne of working fluid passing through the turbine. This metric is more relevant as this directly impacts the capital and operating costs of the system though a larger turbine and condenser and higher parasitic load for the condenser fans.

For each brine temperature and working fluid studied, the optimal conditions were found. In Figure 5, the 1st law efficiency of each of these optimal points is plotted against brine supply temperature.

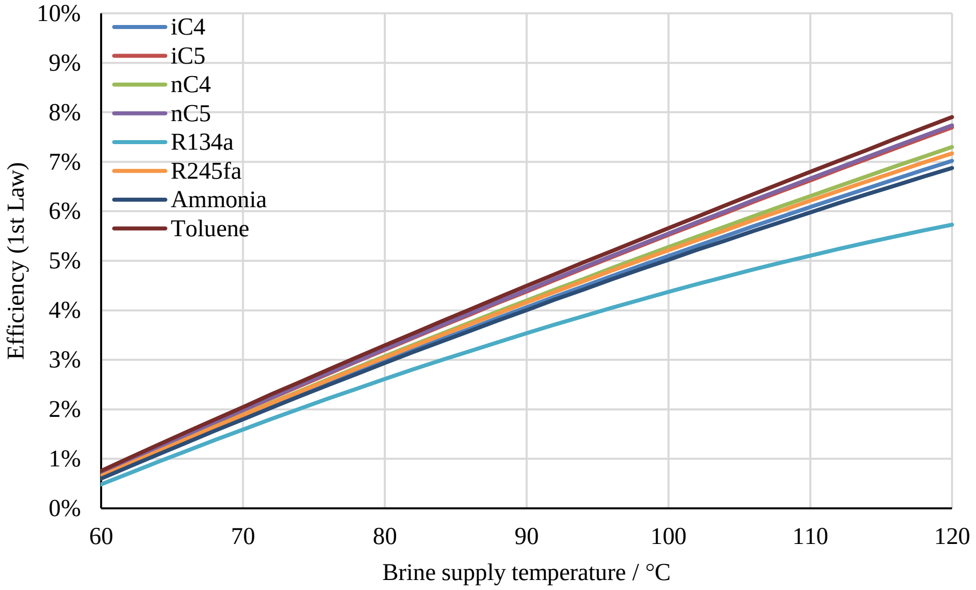

Figure 5. Graph of 1st law efficiency for optimal ORC configurations at a variety of brine supply temperatures.

Figure 5 shows that ORC efficiency increases with brine supply temperature. This is an expected result from the calculation as outlined. From this analysis it was found that toluene was the most efficient working fluid over the temperature range studied. With an expected brine supply temperature of 90°C from the studied Colombian oilfields, a 1st law efficiency of ~4-4.5% can be expected with all working fluids. Efficiency can also be measured relative to the ambient temperature using the 2nd law efficiency, this is plotted in Figure 6.

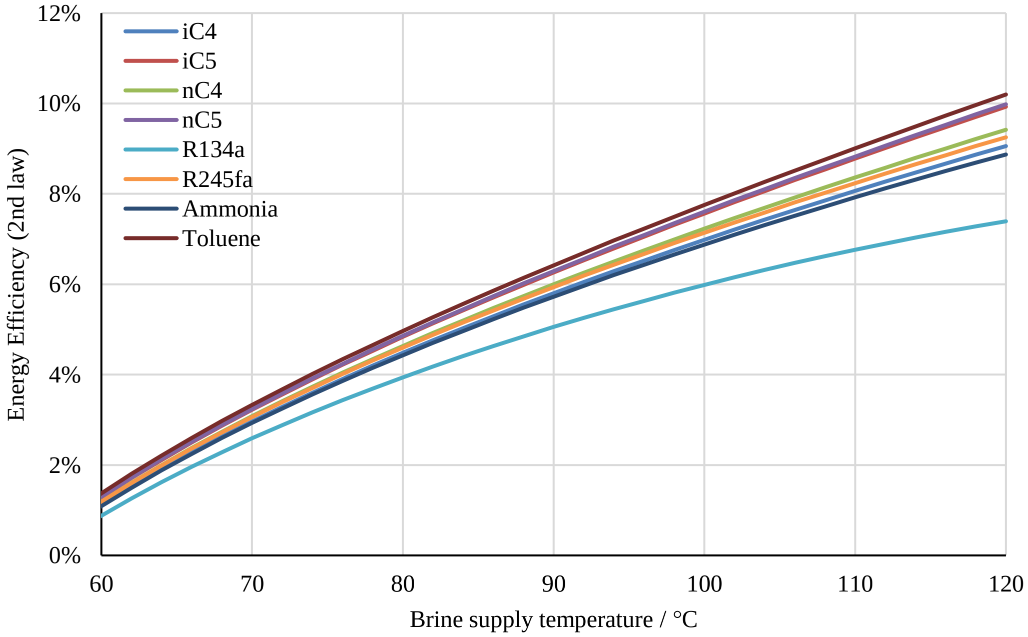

Figure 6. Graph of 2nd law efficiency for optimal ORC configurations at a variety of brine supply temperatures.

Figure 6 shows that 2nd law efficiency is significantly higher than 1st law efficiency - again an expected result. These efficiencies are lower than those seen in other geothermal projects due to the high ambient temperature. This analysis reinforces the selection of the optimal working fluid as toluene with pentane (both isomers) a close second.

These studies have, in effect, optimised the ORC design to minimize operating cost (OPEX). The design of an ORC can also be optimized with respect to capital cost (CAPEX), which is primarily affected by heat exchanger area, operating pressure, and working fluid flowrate. For the 90°C brine supply temperature expected for Colombian oilfields, the evaporator pressure, heat exchanger area and working fluid circulation rate are shown in Table 2.

Table 2. Table of ORC operating parameters for a brine supply temperature of 90°C for a variety of working fluids.

Working fluid	Optimal evaporator pressure	Evaporator heat exchange area	Working fluid circulation rate
[Units]	[kPa (absolute)]	[m²]	[t/h]
iso-butane	971	460	17.5
iso-pentane	310	480	16.5
n-butane	719	469	15.8
n-pentane	246	482	15.5
R134a	1898	433	33.7
R245fa	529	482	31.6
Ammonia	2937	472	5.1
Toluene	23	492	14.1

Table 2 shows that operating pressures range from 23 to 1898 kPa. In general pressures near to, but above ambient indicate lowest capital cost equipment. Toluene operates at a significant vacuum pressure indicating significantly higher capital costs. *n*-pentane, however, operates slightly above ambient and is almost as efficient. Heat exchanger areas are relatively constant for all working fluids as this is largely defined by the brine supply flowrate. Working fluid circulation rate varies significantly due to the makeup of the working fluid, the hydrocarbon working fluids have similar circulation rates with synthetic refrigerants having higher circulation rates and ammonia having a very low circulation rate. Brine flowrates required are effectively independent of working fluid with required flowrates decreasing exponentially as brine supply temperature increases, at 90°C, 50t/h of fluid is required to generate 100 kWe (gross).

3.2 Technical summary

From this analysis, considering operating and capital cost expenses, n-pentane is the most appropriate working fluid. This finding is supported by industrial realities - as n-pentane is a commonly used working fluid in geothermal ORC units worldwide. This appears not to be impacted by the low supply temperature or high ambient temperature in Colombia. Recent studies on similarly designed low temperature ORC units indicates that R245fa is the optimal working fluid (Gosnold, 2015). These results did not support this finding, but this may be due to the UNIFAC physical properties estimation required to use this fluid in HYSYS or the high ambient temperature.

Addressing the assumptions made in this work would likely reduce the efficiencies calculated but would not change the outcome. The degrees of subcooling and superheating have been constant and relatively low (2-5°C). Additional efficiency could be gained by increasing superheat degree for some fluids, but efficiency is likely to drop by increasing other parameters. Additionally, including a reasonable level of pressure drop in all heat exchangers would largely be accounted for by increasing pump duty which had little impact on parasitic load. Equipment between the turbine and condenser cannot be compensated for in this way and frictional pressure losses here would have an impact on efficiency especially for fluids with lower operating pressures.

3.3 Economic results

The financial metrics discussed previously were determined for the project. A sensitivity analysis was performed, altering the equity to debt ratio. This analysis and the results of all determined metrics are shown in Table 3. For all scenarios considered, a project payback of 7 years was determined, with an IRR of 12.7%. These values show that the project is economically feasible whether financed by the developer or by a bank loan. This analysis shows a LCOE between $48-56 USD/MWh which is significantly lower than the reported cost of electricity from diesel generators of $280 USD/MWh (Masum *et al.*, 2021).

Table 3. Table of economic results calculated for a variety of equity/debt ratios.

Equity % / Debt %	Project NPV	Equity NPV	Equity IRR	Equity payback	LCOE (USD/MWh)	WACC
100/0	$ 137,293	$ 137,293	13%	7	55.83	7.4%
90/10	$ 152,876	$ 142,792	13%	6	54.96	7.0%
80/20	$ 169,540	$ 148,290	14%	6	54.1	6.6%
70/30	$ 187,378	$ 153,789	15%	6	53.25	6.2%
60/40	$ 206,493	$ 159,287	16%	5	52.42	5.8%
50/50	$ 226,999	$ 164,786	17%	5	51.59	5.4%
40/60	$ 249,021	$ 170,285	19%	4	50.77	5.0%
30/70	$ 272,697	$ 175,783	21%	3	49.97	4.6%
20/80	$ 298,180	$ 181,282	25%	1	49.17	4.2%
10/90	$ 325,638	$ 186,780	30%	0	48.38	3.8%
0/100	$ 355,260	$ 192,279	37%	0	47.61	3.4%

Overall, this economic analysis is positive with commercially attractive payback periods, NPV and IRR. The LCOE is significantly lower than that of the current used electricity sources meaning replacing conventional generators with the specified ORC is an economically feasible project.

4. CONCLUSIONS

Organic Rankine cycle technology has been applied to oilfield operations historically. This technology has not been used in Colombia for any geothermal application. With the expected conditions outlined this project is technically feasible. With such a low heat source temperature, fluid flowrates are significantly higher than equivalent high temperature projects, but as this is a waste product at present this has no significant cost. Optimization was carried out to assess the most appropriate working fluid and operating conditions for this project. This analysis considering OPEX and CAPEX selected *n*-pentane as the most appropriate working fluid, which is supported by its adoption by industry.

The economic feasibility of this project is enhanced significantly by not competing with grid-scale geothermal (or other electricity generation) projects. As a reliable, independent alternative to diesel powered on-site electricity generation, this solution is highly competitive. With a project payback of 7 years and an IRR of 12% this project is economically feasible in its own right. Considering its LCOE of $48-56 USD/MWh this form of electricity generation is far cheaper than diesel generators. As the cost of electricity from diesel generators is largely driven by operating costs this gives an opportunity to have both forms of generation available for increased resilience with little added cost.

Overall, this project is technically and economically feasible and presents a low-cost and low carbon alternative to current practices. In addition is forms a realisable step towards implementation of geothermal energy in Colombia.

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APPENDIX

Table 4. Table of CAPEX estimations for various elements of the plant.

Item	Price (USD)
Administrative fees	
Supervision, contracting, commissioning	$22,500
Equipment	
Pipelines from well to binary unit	$37,500
Pipelines from binary unit to reinjection well	$37,500
Civil works	
Pad	$4,000
Transmission lines	$12,500
ORC plant	$125,000
Estimated total CAPEX	$239,000
CAPEX per kW	$2,390/kW

Table 5. Table of assumed economic parameters

Assumption	Unit	Value
Capacity	kW	100
Project lifespan	Years	30
Plant capacity factor	%	90
Electricity generation per year	MWh/year	788
CAPEX	USD	239,000
Cost of equity Ke	%	7.4
Average cost of debt	%	5
Debt maturity period	Years	15
Debt grace period	Years	2
Corporate tax	%	33
Tax exemption	Years	15
Depreciation	Years	20
OPEX	USD/MWh	8
Insurance, cost of sales	USD/MWh	3.85
Transmission cost	USD/MWh	0
Resource decline	%	0
Inflation	%	1.6
Construction period	Years	2
Electricity sale price	USD/MWh	65
Electricity price increase	USD/MWh/year	1.3