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Sustainability Analysis of an Advanced Geothermal Energy Storage System

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ABSTRACT

This study focuses on the sustainability design of an Advanced Geothermal Energy Storage (AGES) system installed in a low temperature sedimentary basin. An AGES system functions by injecting heat collected from renewable energy sources and industrial waste heat into a repurposed oil and gas well, and it provides an alternative and sustainable approach to conventional geothermal energy systems. Using this new approach, the cost and site-specific limitations are improved. Existing studies focus on the investigation of the technical feasibility of AGES systems and simplified economic and environmental analyses. In this study, a systematic approach is used to evaluate the levelized cost of energy (LCOE) and a life cycle assessment (LCA). The net present value was determined by considering the surface installation costs and operational and maintenance (O&M) costs over an analysis period of 30 years. The results indicate that the AGES system has a LCOE of 13.5 ¢/kW and produces 16.5 times fewer CO_2 emissions compared to fuel-based energy. These results show great potential for the implementation of AGES systems, which offer significant potential in terms of both economic and environmental aspects. These systems offer a financially viable option with attractive profit margins, while also significantly reducing environmental footprints.

Keywords: AGES, geothermal energy storage, sustainable design, economic indicator, environmental indicator, life cycle costing, life cycle analysis

1 INTRODUCTION

To decarbonize the energy sector and transition to green energy sources to reduce greenhouse gas emissions, the deployment of renewable energy sources has been increasing. In the United States, the share of renewables in the electricity generation mix is expected to increase to 42% in 2050 (EIA, 2022). The primary challenge of integrating renewable energy sources into the power grid is the intermittent nature and dependence on diurnal or seasonal patterns such as wind and solar (Bajaj and Singh, 2020). This shortcoming necessitates efficient and scalable energy storage systems. Energy storage systems provide significant opportunity for (1) secure grid stabilization, (2) stable power-quality and reliable management, (3) load shifting, and (4) grid operational support (Suberu et al., 2014). Available energy storage systems are divided into four types, including (1) electromagnetic, (2) electrochemical, (3) mechanical, and (4) thermal. The selection of the type mainly depends on the storage capacity, efficiency, and cost (Aktas and Kircicek, 2021). These systems are divided into short-term storage systems which are suited for micro-grid applications, and long-term storage systems for utility scale such as large-scale energy generation and distribution levels. Thermal energy storage systems can be deployed for both short and long-term storage. For heating and cooling applications, systems such as soil-borehole thermal energy storage systems have proven to be a convenient alternative to other systems due to their cost-effective and are space efficiency (Baser and McCartney, 2018). Underground energy storage systems hold great potential for the integration of large amounts of renewable resources. The porous medium provides an excellent host to store the energy carried by the injected fluid. Zheng (2014) proposed high temperature subsurface thermal energy storage (HSTES) technology and evaluated the feasibility of electricity generation through solar-HSTES system. Green et al. (2021)

discussed implementing a geothermal battery energy storage “GBES” in sedimentary basins to provide a cost-effective large-scale energy storage for solar and wind power.

Advanced Geothermal Energy Storage (AGES) systems by repurposing existing hydrocarbon (oil and gas) wells present an alternative sustainable technology to existing storage systems, minimizing cost and location limitations. An AGES system operates by injecting heat collected from various renewable or industrial heat sources into the existing wells using existing wells, creating an artificial geothermal underground reservoir for storage. The stored heat can be harvested later for direct use or electricity generation depending on the heat storage capacity of the subsurface. The proposed system aims to overcome the geographical limitation that hinder the wider development of geothermal energy. To address costs, integrating the system with abandoned hydrocarbon wells can eliminate any drilling expenses. Additionally, abandoned wells serve as conduits for gases and liquids to escape from the hydrocarbon bearing formation to potable aquifers and to the atmosphere. Therefore, repurposing the well will not only yield economic benefits, but also mitigate any potential negative environmental impact (Jello and Baser, 2022). The conceptual schematic of the proposed AGES system is shown in Figure 1. Tapping into the AGES system potential provides a promising energy storage system that contributes to low carbon energy development goals (Jello et al., 2022).

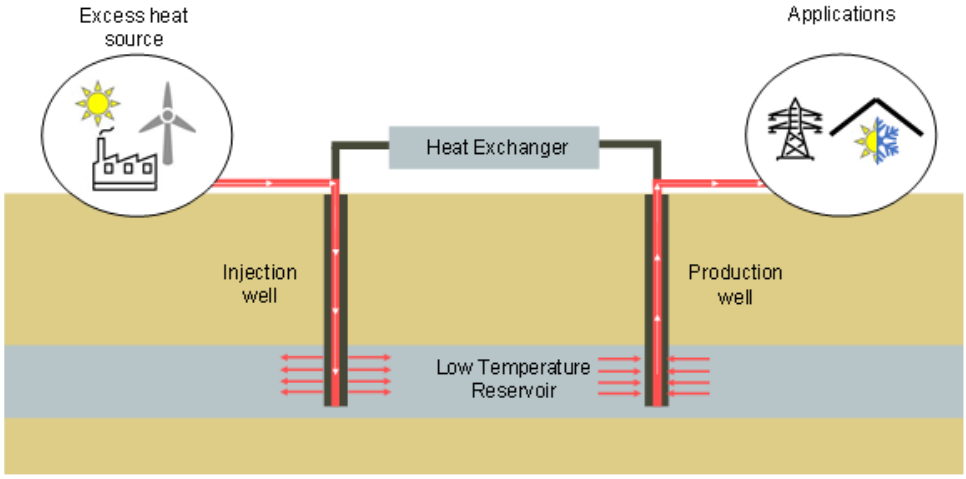


Figure 1. *Conceptual schematic of an AGES system (Adopted from Jello et al., 2022)*

Wendt et al. (2019) performed an economic analysis on a geological thermal energy storage (GeoTES) system in a low temperature sedimentary basin where the storage system was hypothetically connected to a concentrated solar power, and they found the levelized cost of electricity (LCOE) to be $0.13/kWhe. Wendt et al. (2019) reported a long storage duration having relatively high capacity compared to electrochemical battery energy storage systems which can has an LCOE of $0.148/kWhe for 4 hours of storage. Sharan et al. (2021) performed a techno-economic study on an integrated a geothermal energy storage medium with solar power and they reported that the LCOE varies between 10 and 16.4 ¢/kWhe depending on the type of solar collector selected. Although these findings provide a good basis for the techno-economic basis for geothermal energy storage systems, they rely on hypothetical scenarios. Therefore, this study focuses on the sustainability analysis of an AGES system studied in a field-scale as described in Jello et al. (2022). In this paper, the economic and environmental aspects of an AGES system are evaluated, and a sensitivity analysis was performed on the parameters affecting the system performance.

2 CASE STUDY

To investigate the feasibility of an AGES system in low-temperature subsurface basin using an existing gas well, a field test was conducted to characterize the thermal energy potential of the reservoir. Initially, available data sets related to existing wells, including petrophysical, geological, and hydraulic data, were analysed to evaluate the thermo-hydraulic properties of the geologic formations and identify potential target reservoirs. Following a thorough screening, the Cypress formation was selected for the field test due to its favourable properties and its prevalence throughout the basin. The field test comprised a hot fluid injection test and a cold fluid injection test, each followed by a shut-down period to monitor the pressure fall off and thermal stabilization. The well was perforated at interval 901.5 to 903m to inject water. Instrumentation included flow meters, surface pressure and temperature gauges, downhole

pressure, and temperature gauges and integration of a fiber optic distributed temperature sensing (DTS) cable. Further details about the field test can be found in Jello and Baser (2022). Table 1 summarized the field test details.

Table 1. *Field test details*

	Heat injection test	No operation	Cold injection test	No operation
Start date	4/5/2021	4/9/2021	4/15/2021	4/17/2021
End date	4/8/2021	4/14/2021	4/16/2021	4/21/2021
Operational details	T_{inj} = 50℃ Flow rate: Ranged from 0.32 to 0.5 kg/s	Thermal stabilization and pressure decay monitoring	T_{inj} = 16℃ Flow rate: Ranged from 0.13 to 0.38 kg/s	Thermal stabilization and pressure decay monitoring

A two-dimensional axisymmetric model that considers coupled thermal and hydraulic processes was developed to simulate AGES operations for a single push-pull well. The model was implemented with COMSOL Multiphysics v5.4b using the finite element method. The model was first validated using the model reported in Panja et al. (2019), and then calibrated against the data collected from the field test. Using the numerical model, four different operational schemes were simulated and analysed for an operation period of 5 years. Each scheme was evaluated with and without a preheating period. A preheating period extends over 90 days and the cycle consisted of daily injection of hot water for 10 hours at 250 ℃ at a rate of 40 kg/s. Scheme 1 involved a monthly alternating injection/production at a flow rate of 10 kg/s and injection temperature of 250 ℃. For scheme 2, the same scheme was adopted but the flow rate was increased to 40 kg/s. Scheme 3 and 4 involved three-month injection period at a temperature of 250 ℃, followed by a three-month rest period, then a three-month production period, followed by another three-month rest period, at flow rates of 10 and 40 kg/s, respectively. Figures 2(a) and 2(b) presents the temperature variation over the 5-years analysis period for the 4 schemes. Schemes 1 and 2 were adopted from Zheng (2014), which involved an alternating monthly injection/production. Schemes 3 and 4 followed the approach proposed by McLing et al. (2019), where the cycle consisted of an injection period for three months to represent the summer period, followed by a three-month rest period to reflect fall, and then a three-month production period to simulate winter. The scheme ends with a three-month rest period during spring.

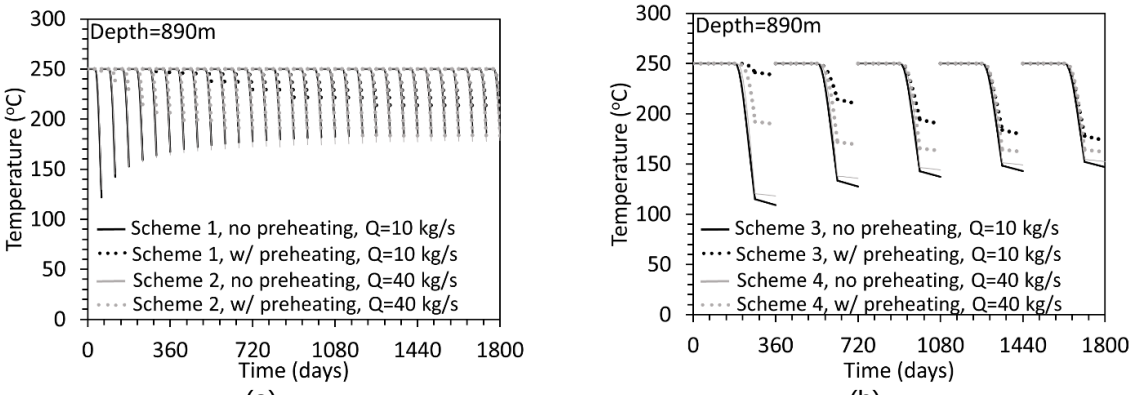
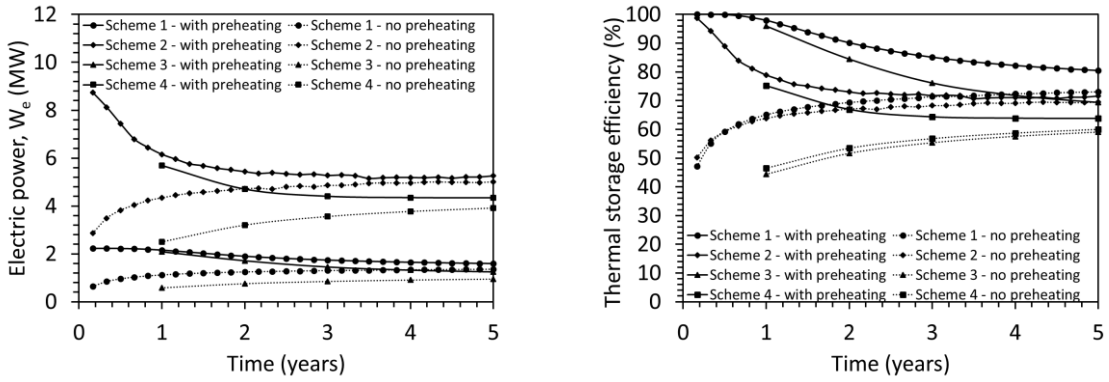


Figure 2. *Temperature variation over time for a period of 5 years for (a) Scheme 1 and Scheme 2; and (b) Scheme 3 and Scheme 4 (Adopted from Jello et al., 2022)*

The thermal heat produced was converted to electric power using an efficiency conversion factor. More details can be found in Jello et al., 2022. The power generation in the AGES system proposed was computed for the four schemes. The evolution of the electric power W_e and thermal storage efficiency η_s over the 5-years analysis period are shown in Figures 3(a) and 3(b) respectively. Results predicted that Scheme 2 generated the highest power generation with 251 GWh with a preheating period and 202 GWh without a preheating period.



(a) (b)

Figure 3. *Time series of (a) Electric power (W_e); and (b) Thermal storage efficiency (η_s) (Adopted from Jello et al., 2022)*

3 METHODOLOGY

To assess the project finances, 10 wells were considered for an analysis period of 30 years, and the net present value (NPV) is determined using equation (1) as follows:

$$\mathrm{NPV} = \sum \frac{\mathrm{Cash\ flow}_{\mathrm{year\ n}}}{(1+\mathrm{r})^{\mathrm{n}}} \tag{1}$$

where r is the discount rate and n is the project year. The analysis period considered is 30 years and a discount rate of 13% is assumed. Since abandoned oil and gas wells will be repurposed for the proposed system, where exploration data exists, the subsurface costs, including drilling and exploration, are insignificant compared to the total cost and will not be considered. For the surface installation costs, they were estimated using equation (2) as suggested by Stefansson (2001). By analysing economics of existing projects, Stefansson (2001) derived an empirical correlation between cost of surface installation and size of the geothermal plant.

$$\text{Surface cost (M\$)} = (-0.9 \pm 4.6) + (1 \pm 0.1) * \mathrm{P} \tag{2}$$

Valid in the range 20-60 MW

where P is the power output generated from the system (MW). The yearly operational costs for the system were assumed from existing data for geothermal systems (NREL, 2022). The LCOE is calculated using equation (3) to determine the baseline cost of electricity generation ($/kWh):

$$\mathrm{LCOE} = \frac{\mathrm{NPV}_{\mathrm{Project\ costs}}\ (\$)}{\mathrm{NPV}_{\mathrm{electricity\ output}}\ (\mathrm{kWh})} \tag{3}$$

To perform the life cycle analysis (LCA) of the proposed system, equivalent CO_2 emissions is used as an indicator to assess the environmental impact and is calculated using equation (4) as proposed in Li et al. (2021):

$$\mathrm{CO}_{2,eq} = \mathrm{P} \times \mathrm{EF} \tag{4}$$

where $CO_{2,eq}$ is the equivalent CO_2 emissions (kg/kWh) and EF is the CO_2 emission factor for electricity. The emission factor for geothermal systems for electricity is on average 37 gCO_{2eq}/kWh and is compared to a reference value of 648 gCO_{2eq}/kWh for fossil fuel energy (Nicholson et al., 2021)

4 RESULTS ANALYSIS

The LCOE for the four schemes simulated was calculated considering a total of 10 wells and an analysis period of 30 years. The costs considered for the analysis are summarized in Table 3.

Table 3. *Costs used for the analysis (Stefansson (2001); NREL (2022))*

		Installation Costs (M/$)			O&M ($/KW/yr)		
		Lower	**Upper**	**Average**	**Lower**	**Upper**	**Average**
S1	**Charging**	12.50	25.70	19.10	99	107	103
	No Charging	12.50	25.70	19.10	99	107	103
S2	**Charging**	46.16	66.84	56.50	99	107	103
	No Charging	36.08	54.52	45.30	99	107	103
S3	**Charging**	12.50	25.70	19.10	99	107	103
	No Charging	12.50	25.70	19.10	99	107	103
S4	**Charging**	31.40	48.80	40.10	99	107	103
	No Charging	25.01	40.99	33.10	99	107	103

The LCOE for the four schemes is shown in Figure 4. The LCOE varies between 13.5 and 24.4 ¢/kWh. Schemes 1 and 3 have a higher LCOE than Schemes 2 and 4 because they operate at a lower flow rate (10 kg/s) and yield a lower power output. For Schemes 2 and 4, the difference between charging and no charging is insignificant which can be attributed to the higher flow rate applied. Under these conditions, the charging period does not affect the LCOE and can be skipped. However, for low flow rates, the difference is more significant, and results shows that a charging period would decrease the LCOE due to the increase in power output.

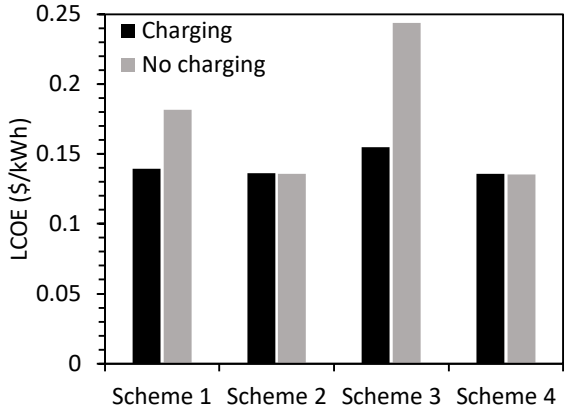


Figure 4. *LCOE for the 4 schemes*

The results comparing the greenhouse gas (GHG) emissions from the proposed system compared to fossil-fuel based system are shown in Figure 5. Results show that the proposed system emits approximately 16.5 times less GHG emissions than a fossil fuel-based system. The results of this study demonstrate the significant potential for integrating the system into the power grid, particularly in regions characterized by a surplus of abandoned oil and gas wells. This integration has the potential to result in a substantial reduction in installation costs and reduce negative environmental impact emitted from the wells.

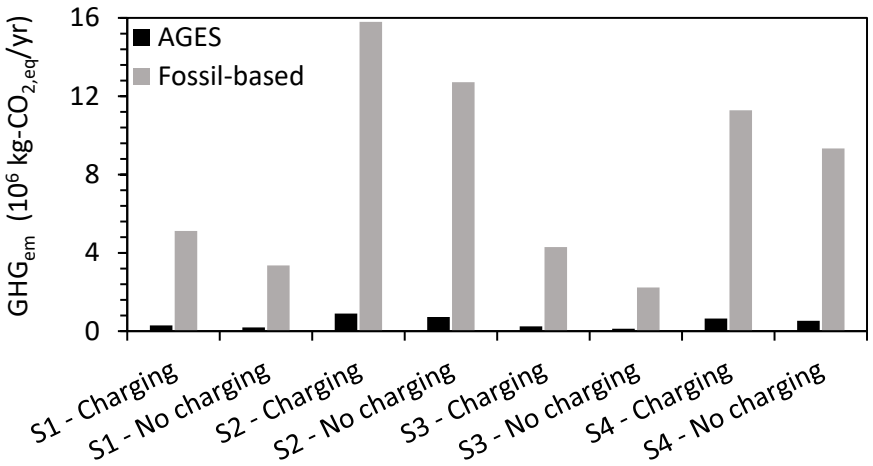
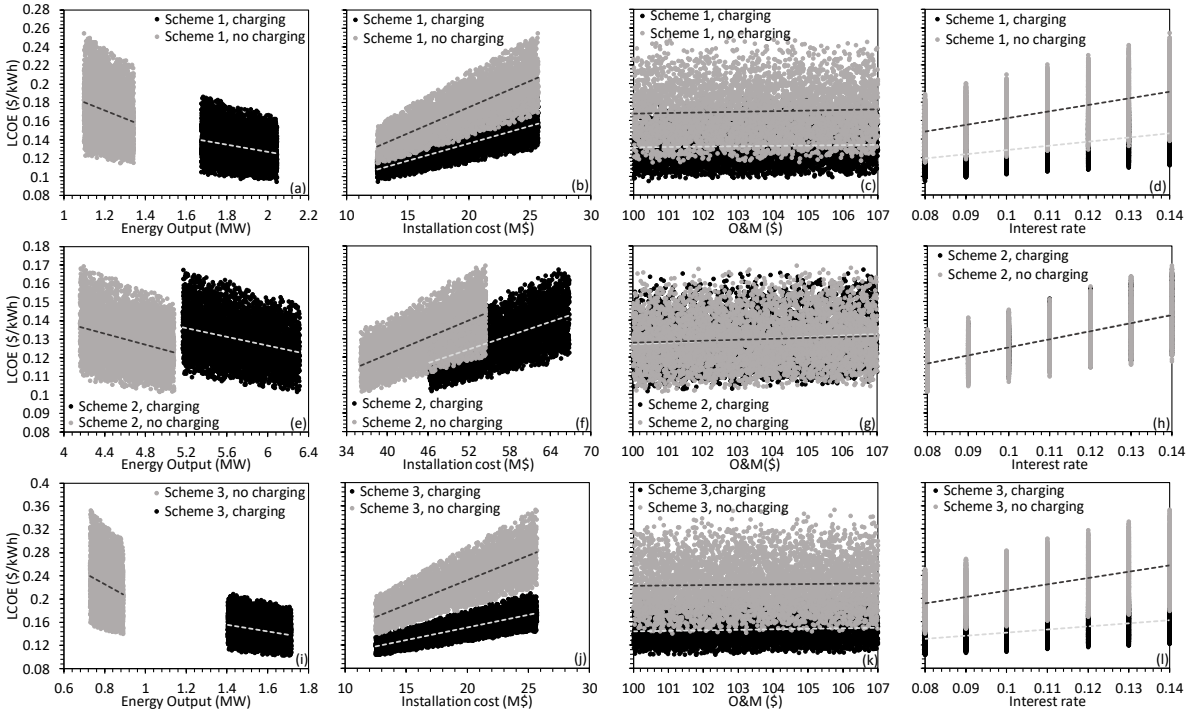


Figure 5. *LCA comparison between the 4 schemes and fossil-based energy*

5 SENSITIVITY ANALYSIS

A Monte Carlo analysis was performed to evaluate the impact of the assumptions on the analysis. A uniform distribution was considered for the following inputs, including the energy output, installation cost, operational and maintenance (O&M) cost, and interest rate. A normal distribution was used for the EF between 20 to 40 gCO_{2eq}/kWh. A total of 5000 sample for each scheme were studied. Figures 6(a) through 6(p) summarize the results of the analysis. Figures 6(a), 6(e), 6(i), and 6(m) show that the energy output and the LCOE are inversely proportional, i.e., the unit cost decrease with an increase in output. Figures 6(b), 6(d), 6(f), 6(h), 6(j), 6(l), 6(n) and 6(p) show that the LCOE is proportional to the installation cost and interest rate. The uncertainty in the O&M cost does not have a significant effect on the LCOE, as shown in Figures 6(c), 6(g), 6(k) and 6(o).



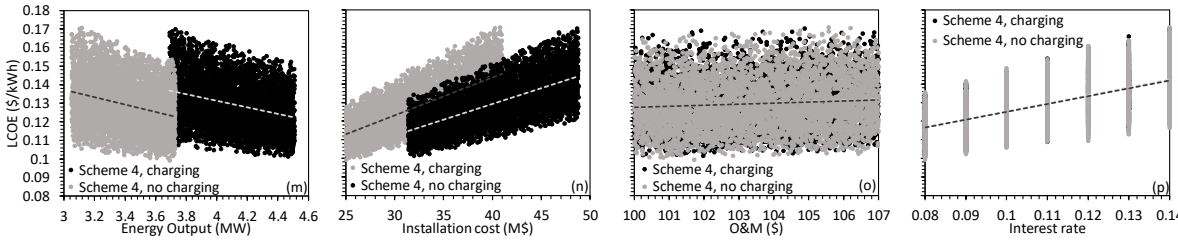


Figure 6. *Sensitivity analysis for the (a) energy output - S1; (b) installation cost-S1; (c) O&M-S1; (d) interest rate-S1; (e) energy output - S2; (f) installation cost-S2; (g) O&M-S2; (h) interest rate-S2; (i) energy output - S3; (j) installation cost-S3; (k) O&M-S3; (l) interest rate - S3; (m) energy output-S4; (n) installation cost-S4; (o) O&M-S4; and (p) interest rate-S4*

The uncertainty in the assumed EF is shown in Figure 7. Results show that for schemes 1 (charging and no charging) and scheme 3 (charging and no charging), the values are close to the median values, indicating low variability in the results. However, at high flow rates (Scheme 2: charging and no charging and Scheme 4: charging and no charging), the discrepancy between the median and the minimum and maximum values is larger, indicating higher uncertainties. This can be attributed to higher fluctuations in the power output under those operational conditions. The cases with no charging exhibit more variations in the LCA results. This demonstrates that a charging period can lead to a more stable output, which, in turn, can reduce uncertainty.

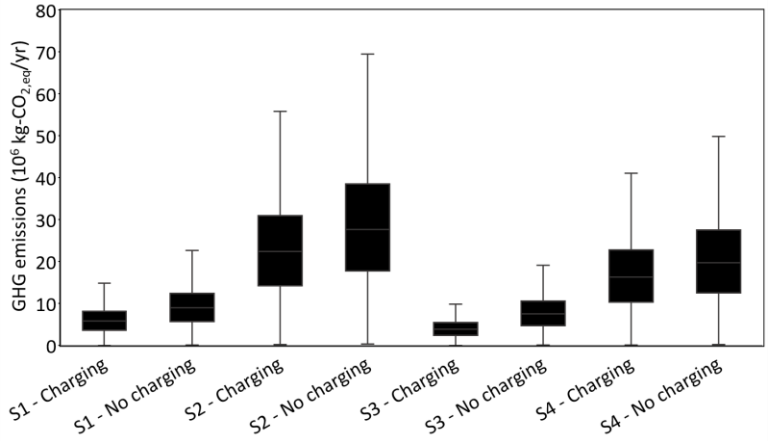


Figure 7. *Uncertainty analysis for the LCA results*

6 CONCLUSIONS

This paper focused on evaluating the economic and environmental impacts of an AGES system. The proposed system operates by injecting a hot fluid into an existing abandoned oil and gas wells to create an artificial geothermal system, which would eliminate the cost and location limitations. An LCOE and LCA analyses were performed to assess the economic viability and environmental impact of an AGES system. The conclusions are as follows:

- The LCOE of the AGES system varies between 13.5 and 24.4 ¢/kWh, depending on the flow rate selected, where the unit cost increases with a decrease in the flow rate.
- A charging period decrease the LCOE at low flow rates, but its application is insignificant for high flow rates.
- An AGES emits on average 16.5 times less CO_2 than fossil-fuel based energy.
- The energy output is negatively correlated with the LCOE, whereas the installation cost and interest rate are proportional to the LCOE.
- At higher flow rates, the uncertainty in the LCA is higher than at lower flow rates. However, the emissions are still much lower than fossil-fuel based energy.

Future work will implement the system in a real-world case study and specific geographical region will be explored. This will involve employing more advanced LCOE and LCA analyses that comply with the design criteria and chosen location. Furthermore, additional configurations will be simulated and compared to optimize the design.

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