Application of Supercritical Carbon Dioxide in Engineered Geothermal Systems

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I hereby certify to the best of my knowledge and belief that the work done in this thesis is original and contains no material previously published or written by another person, except where due reference has been made in the text.

Alvin I. Remoroza
I hereby certify that the work embodied in this thesis contains published papers/scholarly work of which I am a joint author. I have included as part of the thesis a written statement, endorsed by my supervisor, attesting to my contribution to the joint publications/scholarly work.

Alvin I. Remoroza
I, the undersigned, certify and endorse that several publications listed in the thesis were based from Alvin's thesis from which he contributed and therefore recognised as a co-author.

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Table of Contents

Abstract i
List of Figures vi
List of Tables xxiv
List of Publications xxv

Chapter 1: Introduction 1
  1.1 Motivation 2
  1.2 Overview of the CO₂ Based EGS Power Generation 4
  1.3 The Present Work 5
  1.4 Thesis Structure 7

Chapter 2: Literature Review 10
  2.1 Engineered Geothermal Systems 10
    2.1.1 Australian EGS Resource Base 12
    2.1.2 EGS Economic Model 15
    2.1.3 Drilling Technology and Cost 20
    2.1.4 Reservoir Engineering and Management 21
    2.1.5 Energy Conversion Technologies 22
    2.1.6 Water Requirement and Availability 25
  2.2 CO₂-Engineered Geothermal Systems 27
  2.3 Research Gaps 33

Chapter 3: Theoretical Background 36
  3.1 Thermodynamics of Geothermal Power Plant Cycles 36
    3.1.1 Components of Geothermal Power Systems 38
    3.1.2 Thermodynamics of Flash Cycles 40
    3.1.3 Thermodynamics of Organic Rankine Cycles 51
    3.1.4 Exergy Analysis 53
  3.2 Geothermal Reservoir Engineering 55
    3.2.1 Simple Reservoir Models 57
    3.2.2 Dual Porosity Model 60
  3.3 Chemistry of Fluid-Rock Interactions 62
    3.3.1 Basic Chemistry Concepts 63
    3.3.2 Kinetics of Reaction 65
3.3.3 Dissolution and Alteration of Minerals

Chapter 4: One and Two-Dimensional Combined Reservoir and Power Plant Cycle Modelling for EGS

4.1 Wellbore and Reservoir Flow Modelling
   4.1.1 Wellbore Flow Calculation
   4.1.2 1D Reservoir Flow Calculation
   4.1.3 2D Reservoir Flow Calculation
   4.1.4 Simulation Inputs for Wellbore and Reservoir Flows
   4.1.5 Heat Extraction Rate
   4.1.6 Exergy

4.2 Power Cycle Modelling
   4.2.1 Simulation Inputs for Power Cycle Modelling

4.3 Results and Discussion
   4.3.1 Optimal Cell Size
   4.3.2 Power Cycle Temperature-Entropy Diagram
   4.3.3 Injection Pressure and Temperature
   4.3.4 Wellbore Flow
   4.3.5 1D Reservoir Flow
   4.3.6 2D Reservoir Flow

4.4 Concluding Remarks

Chapter 5: Three-Dimensional Combined Reservoir and Power Cycle Modelling for EGS

5.1 TOUGH2 Governing Equations

5.2 Integrated Modelling Approach
   5.2.1 Simulation Inputs

5.3 Three-Dimensional Reservoir Model Validation

5.4 Wellbore Heat Transport
   (5.8) 156
   (5.9) 156

5.5 Results and Discussion
   5.5.1 Reservoir-Production Well Connection
   5.5.2 Injection Bottom-hole Temperature
   5.5.3 Reservoir Temperature
   5.5.4 Reservoir Pressure (Depth)
Abstract

The present thesis is concerned with geothermal energy and specifically focuses on engineered geothermal systems (EGS), which are among a portfolio of technology options for power generation from geothermal resources. In this cyclic approach (also known as hot-dry-rocks or enhanced geothermal systems), high pressure water (i.e. "geofluid") is first pumped down a borehole (known as injection well) into a bed of hot fractured rock and forced to travel through the bed, capturing the heat content of the rocks. The hot water is then extracted from a second borehole (known as production well) and sent into a binary power plant, where its thermal energy is converted to electricity. The cooled water exiting the power plant is then injected back into the ground to resume the cycle.

The aim of this thesis is to advance the understanding of CO$_2$ based EGS power generation process and verify the merits of using CO$_2$ rather than water for heat extraction from fractured hot dry rocks. The work has been largely driven by the suitable thermodynamic and transport properties of supercritical CO$_2$ (scCO$_2$), which makes it a desirable candidate for harnessing geothermal energy from hot dry rocks, particularly in regions where water resources are scarce. However, only a limited number of studies were carried out in the past to assess the viability of the CO$_2$ based EGS concept. Most of these studies were theoretical examinations of the heat extraction and exergy analysis under a limited range of operational parameters. In addition, research work on the fluid-rock interactions relevant to CO$_2$ based EGS is also limited and needs further investigation. The present thesis addresses the above knowledge gaps through a combined experimental and theoretical study, resulting to an accurate description of the entire CO$_2$ based EGS power generation process encompassing the reservoir, wellbore and power plant cycle as well as the fluid-rock geochemical interaction. The specific objectives of the project underlying this thesis were: (1) model development and simulation of the entire CO$_2$ and H$_2$O based EGS and the associated power plant cycles, (2) optimisation studies and sensitivity analysis of operating and design parameters affecting CO$_2$ and H$_2$O based EGS performance, (3) performance comparison of CO$_2$ based EGS and H$_2$O based EGS under the same operating and
reservoir conditions, (4) examination of the effect of reservoir parameters on both CO₂ and H₂O based EGS concepts through detailed 3D reservoir simulations, (5) design and fabrication of a fluid-rock interaction apparatus capable of simulating EGS conditions, and (6) experimental investigation of the fluid-rock interactions at reservoir conditions and its likely impact on the performance characteristics of CO₂ and H₂O based EGS.

One dimensional (1D), 2D, and 3D models of integrated reservoir-wellbore-power plant cycle were developed to provide an overall description of fluid flow in fractured reservoir (channel flow) and in radial fluid flow in homogeneous porous media. It was also created to investigate "3D effects" as well as transient changes during the power generation process. The thermosiphon power generation process was used in CO₂ based EGS model simulations while the Organic Rankine Cycle binary plant with isopentane as the working fluid was employed in the H₂O based EGS simulations.

Mass and energy balance equations associated with the integrated 1D and 2D reservoir-wellbore-power plant cycle model simulations were solved using the Engineering Equation Solver (EES). In the integrated 3D reservoir-wellbore-power plant cycle modelling, the transient geofluid mass and heat flow rates in the reservoir were simulated using TOUGH2/ECO2N software packages while the wellbore flow and power plant cycle calculations were carried out using EES. The use of TOUGH2/ECO2N was validated and calibrated by replicating the results of prior studies done by Pruess (2008) where TOUGH2/EOSM simulator was used.

A fluid-rock interaction apparatus with titanium made wetted components was designed and fabricated to conduct batch and flow-through experimental studies of rock samples with CO₂ and H₂O at pressures up to 50 MPa and temperatures up to 400°C. Surface granite from Moonbi near New England Highway, NSW and drill core samples from Mossigel 1 and Nambucurra 1 boreholes at Murray-Darling Basin, NSW were collected and used as representatives of hot-dry-rock (HDR) EGS reservoir rock formations. The granite samples were pulverised and analysed for particle size distribution as well as element (fused-bead XRF) and mineral (Rietveld quantitative XRD) compositions prior to any experiments. Fluid-rock interaction experiments were conducted for up to 15 days at different simulated reservoir pressures (20 and 35 MPa) and temperatures
(200 and 250°C). Fluid effluents were analysed using ICP-OES, and the reacted pulverised granite samples were subjected to further XRF, XRD, and SEM (scanning electron microscopy) analysis.

The following are the key findings of the integrated 1D/2D reservoir-wellbore-power simulations:

- The mass flow rate of CO₂ has an inverse relation with the injection temperature in a CO₂ based EGS while there is a direct relationship between the mass flow rate of water and injection temperature in CO₂ based EGS. These contrasting behaviours can be assigned to the fact that an increase in the injection temperature lowers the CO₂ density and hence increases its dynamic viscosity whereas in the case of water, an increase in the injection temperature lowers H₂O kinematic viscosity and thereby decreases the dynamic viscosity.

- Reservoir pressure loss is generally higher for H₂O than for CO₂ because of the higher H₂O kinematic viscosity.

- CO₂ overall mass flow rate is higher than that of H₂O due to lower average CO₂ kinematic viscosity at reservoir conditions.

- Wellbore frictional loss of CO₂ is greater than that of H₂O due to the lower average CO₂ density along the length of the wellbore.

- Heat extraction rates of H₂O based EGS is generally higher than those of CO₂ based EGS due to higher specific heat capacity of water.

- The thermal siphoning is not practical for H₂O based EGS because the production pressure is usually lower than the injection pressure.

- Power generation output of H₂O based EGS are higher than that of CO₂ based EGS and increases almost linearly as injection pressure increases while CO₂ based EGS power output shows a parabolic trend. These were found to be due to the dependency of CO₂ thermodynamic properties on pressure while H₂O thermodynamic properties are almost independent of pressure.
- Reservoir temperature does not influence the overall CO₂ mass flow rate, but CO₂ heat extraction rate increases as reservoir temperature increases due to increase in the specific enthalpy change.

- The maximum power generation of CO₂ based EGS decreases as reservoir pressure decreases due to lower CO₂ production pressure in the wellhead.

- For both CO₂ and H₂O based EGS, shorter injection to production well distance gives higher fluid mass flow rate due to the increase in pressure gradient (pressure drop/distance) between the injection and production wells.

- As the ratio of production to injection well increases, the CO₂ based EGS power generation output increases due to diminishing CO₂ frictional loss in individual production well as the number of production well increases.

- CO₂ based EGS generally performs better in low permeability reservoirs (typically one order of magnitude decrease in reservoir permeability decreases CO₂ mass flow rates by 27% while H₂O mass flow rates decreases by 67%).

- The overall thermal efficiency at any specified injection and reservoir conditions is constant regardless of CO₂ mass flow rate.

Batch and flow-through CO₂-rock interaction experiments show that Ca, Fe, Mg, Al, and Si dissolve in scCO₂, which was found to be partly due to the presence of H₂O in the CO₂ stream leaked from the piston accumulator. Geochemical model simulations show that aqueous Si concentration is in equilibrium with the rock minerals after 1 day exposure in the batch experiment. The log of (Na/K) ratios shows the preferential dissolution of albite over k-feldspar. The SEM image analysis of the treated granites shows signs of erosion (i.e. rounded edges and pebble-like surfaces), which is considered to be due to the formation of carbonates in the surface and its subsequent erosion and dissolution (particularly Na₂CO₃ and K₂CO₃) to the fluid. The XFR analysis of the untreated and treated pulverised granites shows very small changes to SiO₂, Al₂O₃, CaO, MgO, Fe₂O₃, Na₂O, and K₂O major oxide compositions consistent with the ICP-OES analytical results. The Na-K-Mg ternary diagram of the data collected from the fluid-rock experiments shows that the aqueous fluid is far from the equilibrium.
The presence and/or absence of minerals (hornblende or chlorite) in the starting material influences the log of (Na/K) ratios. Hornblende alters or converts to chlorite in the CO\(_2\)-H\(_2\)O mixture. Moreover, the concentrations of Ca, Mg, and Fe decreases with time, which is considered to be due to the formation of a passive layer of insoluble carbonate minerals in the surface, thus preventing further fluid-rock interaction.

The pressure loss data collected during the flow-through fluid-rock interaction experiments validate the theory that CO\(_2\) has lower reservoir loss than H\(_2\)O. The data also validate the correlation between particle size and intrinsic permeability, which predicts that at the same fluid mass flow rate, a medium with a larger particle size has a lower pressure loss.
List of Figures

Figure 1.1: HDR scCO$_2$ System first proposed by Brown (2000). Source: Brown (2000).  
Figure 1.2: Outline of the project accomplished in this thesis.  
Figure 2.1: Estimated crustal temperature at 5 km depth (Geoscience Australia, map derive from the AUSTHERM07 (Chopra & Holgate, 2005) and OZ SEEBASE™ sediment thickness data (FrogTech, 2006)).  
Figure 2.2: Distribution of contained crustal energy. The total resource is 1.9 x $10^{25}$ J, equivalent to 2.6 million times the gross energy consumption in Australia during 2004–05 (Budd et al., 2007).  
Figure 2.3: 2015 technology ranking of different energy technologies in terms of levelised electricity cost and CO$_2$ emissions.  
Figure 2.4: 2030 technology ranking of different energy technologies in terms of levelised electricity cost and CO$_2$ emissions.  
Figure 2.5: Costs of completed geothermal and oil and gas wells as a function of depth in year 2004 U.S. $ (Tester, et al., 2006).  
Figure 2.6: The schematic diagram of Regenerative Supercritical Rankine Cycle (top) after Moghtaderi and Doroodchi (2009). T-s diagram of ORC, Kalina and supercritical rankine cycle (bottom).  
Figure 2.7: The schematic diagram of the Variable Phase Cycle, after Welch and Boyle (2009). VPT means variable phase turbine.  
Figure 2.10: Schematic of the three zones with different phase compositions in an EGS operated with CO$_2$. Source: Xu et al.( 2008).  
Figure 3.1: Typical Dry Steam Geothermal Well (DiPippo, 2008b).  
Figure 3.2: T-s diagram showing isenthalpic lines starting from saturated water.  
Figure 3.3: Schematic Diagram of a Flash Vessel or Steam Separator (Pallson, H., lecture notes).
Figure 3.4: T-s diagram of the process during flashing and separation of water and steam inside a flash vessel.  

Figure 3.5: Schematic diagram summarising the differences between impulse and reaction turbines (Wikipedia Commons).  

Figure 3.6: T-s diagram of a steam turbine process.  

Figure 3.7: T-s diagram of a single flash steam cycle with 85% turbine (isentropic) efficiency.  

Figure 3.8: Schematic diagram of a single flash back pressure cycle.  

Figure 3.9: Schematic diagram of a single flash cycle with condenser.  

Figure 3.10: Optimisation of power output per 1 kg/s flow versus separation pressure of single flash cycle at different saturated liquid aquifer temperatures.  

Figure 3.11: Power output per 1kg/s flow of 250 °C liquid aquifer fluid and steam quality at turbine outlet versus separation pressure.  

Figure 3.12: Schematic diagram of a dual flash cycle with one turbine.  

Figure 3.13: Schematic diagram of a dual flash cycle with two turbines.  

Figure 3.14: T-s diagram of an optimised dual flash steam cycle for 250 °C saturated liquid aquifer.  

Figure 3.15: Schematic diagram of a binary plant using ORC.  

Figure 3.16: Schematic diagram of a binary plant using ORC with recuperator.  

Figure 3.17: T-s diagram of an ORC with isopentane as the organic fluid.  

Figure 3.18: Basic pressure-transient model of a vertical well (Grant & Bixley, 2011b).  

Figure 3.19: Idealised dual porosity model (Grant & Bixley, 2011b).  

Figure 3.20: Multiple interacting continua. Modified after (K. Pruess & Narasimham, 1985).  

Figure 3.21: Na-K-Mg ternary diagram for geothermal fluid assessment.  

Figure 4.1: Schematic diagram of a Darcy 1D reservoir flow model flow.  

Figure 4.2: Discretisation of the wellbore height into small elements with Δz length. The diagram also shows how the nodes (i.e. 1, 2, 3, 4..n, n+1) were indexed.  

Figure 4.3: Schematic diagram of a 2D radial reservoir flow model.
Figure 4.4: Process flow diagram of a typical CO$_2$ thermosiphon power cycle.

Figure 4.5: Process flow diagram of a typical binary plant for H$_2$O based EGS.

Figure 4.6: Sensitivity of the predicted mass flow rate on the calculation element size.

Figure 4.7: A typical temperature-entropy diagram of a CO$_2$ thermosiphon power cycle.

Figure 4.8: A typical temperature-entropy diagram of the binary power cycle with isopentane as the working fluid.

Figure 4.9: Fluid mass flow rate versus injection pressure at different injection temperatures.

Figure 4.10: Density of CO$_2$ and H$_2$O versus pressure at various temperatures.

Figure 4.11: Kinematic viscosity of CO$_2$ and H$_2$O versus temperature at various pressures.

Figure 4.12: Injection well frictional loss versus injection pressure at different injection temperatures.

Figure 4.13: Injection well bottom-hole pressure versus injection pressure at different injection temperatures.

Figure 4.14: Reservoir pressure loss versus injection pressure at different injection temperatures.

Figure 4.15: Heat extraction rate versus injection pressure at different injection temperatures.

Figure 4.16: Pressure-enthalpy diagram of H$_2$O.

Figure 4.17: Pressure-enthalpy diagram of CO$_2$.

Figure 4.18: Fluid production pressure of fluid versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.

Figure 4.19: Production well frictional loss versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.

Figure 4.20: Fluid production temperature versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.

Figure 4.21: Total exergy versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.
Figure 4.22: Fluid specific exergy created from injection wellhead to the production wellhead versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.

Figure 4.23: Power generation versus injection pressure at different injection temperatures. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 1km reservoir length.

Figure 4.24: Temperature (left plots, lower X-axis) and pressure (right plots, upper X-axis) well profile at the injection well. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.25: Effect of well wall roughness on the mass flow rate. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.26: Well frictional loss versus injection pressure at different well wall roughnesses. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.27: Effect of well wall roughness on total fluid exergy. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.28: Effect of well wall roughness on power generation. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.29: Hypothetical 5000 m geothermal well with multi-diameter design.

Figure 4.30: CO₂ mass flow rate comparison between multi and single diameter casing design. Simulation conditions: 5 km well depth, 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.31: The effect of well to well distance on fluid mass flow rate. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 25°C injection temperature.

Figure 4.32: Reservoir pressure gradient versus injection pressure at different well to well distances. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 25°C injection temperature.

Figure 4.33: The effect of injection to production well distance on total exergy. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 25°C injection temperature.
Figure 4.34: Total power generation potential at different injection to production well distances. Simulation conditions: 5 km well depth, 225°C reservoir temperature, and 25°C injection temperature.

Figure 4.35: Geothermal fluid mass flow rates at different reservoir temperatures. Simulation conditions: 5 km well depth, 225°C injection temperature, and 1 km reservoir length.

Figure 4.36: Fluid heat extraction rates at different reservoir temperatures. Simulation conditions: 5 km well depth, 25°C injection temperature, and 1 km reservoir length.

Figure 4.37: Total exergy at different reservoir temperatures. Simulation conditions: 5 km well depth, 25°C injection temperature, and 1 km reservoir length.

Figure 4.38: Power potential at different reservoir temperatures. Simulation conditions: 5 km well depth, 25°C injection temperature, and 1 km reservoir length.

Figure 4.39: Geothermal fluid mass flow rate at different reservoir depths. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.

Figure 4.40: Reservoir pressure gradient at different reservoir depths. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.

Figure 4.41: Fluid total exergy at different reservoir depths.

Figure 4.42: Total power potential at different reservoir depths. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.

Figure 4.43: Production pressures at different reservoir depths. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.

Figure 4.44: Geothermal fluid mass flow rate predicted by 1D and 2D reservoir models. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km well depth, and 1 km reservoir length.

Figure 4.45: Ratio of fluid mass flow rate predicted by 2D to that of 1D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.

Figure 4.46: Reservoir pressure loss comparison between 1D and 2D reservoir model predictions. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1 km reservoir length.
Figure 4.47: CO₂ 1D and 2D reservoir pressure profile from injection to production wells at 7.5 MPa injection pressure. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.48: Total exergy predictions using 1D and 2D reservoir flow models. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.49: Total power generation potential of CO₂ and H₂O based EGS using 1D and 2D reservoir models. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km reservoir length.

Figure 4.50: Effect of the injection to production well ratio on fluid mass flow rates. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

Figure 4.51: Effect of the injection to production well ratio on the fluid total exergy. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

Figure 4.52: Effect of the injection to production well ratio on EGS power generation potential. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

Figure 4.53: Effect of the injection to production well ratio on the frictional loss at the production well. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

Figure 4.54: Production pressure using different injection to production well ratios. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

Figure 4.55: Production temperature using different injection to production well ratios. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

Figure 4.56: Geothermal fluid mass flow rate at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

Figure 4.57: Injection well frictional loss at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation
conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

**Figure 4.58:** Normalised frictional loss in the injection well at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

**Figure 4.59:** Reservoir pressure gradient at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

**Figure 4.60:** Total fluid exergy at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

**Figure 4.61:** EGS power potential at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

**Figure 4.62:** CO₂ production temperature (red lines) and pressure (secondary y-axis, blue lines) at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, and 1km injection to production distance.

**Figure 4.63:** The predicted specific exergy at different reservoir depths using 1:4 injection to production well ratio and 2D reservoir model.

**Figure 4.64:** Geothermal fluid mass flow rate at different reservoir permeabilities using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

**Figure 4.65:** EGS power potential at different reservoir permeability using 1:4 injection to production well ratio and 2D reservoir model. Simulation conditions: 225°C reservoir temperature, 25°C injection temperature, 5 km reservoir depth, and 1km injection to production distance.

**Figure 5.1:** A five-spot well configuration: (a) top view of ¼ section with an injection-production segment and (b) 3D reservoir model simulation.

**Figure 5.2:** Pressure profile of the 3D reservoir model after gravity equilibration. The fluid used was CO₂, and the top layer conditions were set to 20 MPa and 200°C.
Figure 5.3: The CO₂ mass flow rate and heat extraction rate from this study (top) and prior studies done by Pruess (2008, bottom) for well design where all layers of the reservoir were open to production using 12×12 areal grids, rock matrix permeability of 1.9×10⁻¹⁴ m², and rock matrix porosity of 0.2%. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.4: The CO₂ mass flow rate and heat extraction rate from this study (top) and prior studies done by Pruess (2008, bottom) for well design where only the topmost 50 m layer of the reservoir was open to production using 12×12 areal grids, rock matrix permeability of 1.9×10⁻¹⁴ m², and rock matrix porosity of 0.2%. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.5: The CO₂ mass flow rate and heat extraction rate from this study (top) and prior studies done by Pruess (2008, bottom) for well design where all layers of the reservoir were open to production using 24×24 areal grids, rock matrix permeability of 5×10⁻¹⁴ m², and rock matrix porosity of 0.2%. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.6: The CO₂ mass flow rate and heat extraction rate from this study (top) and prior studies done by Pruess (2008, bottom) for well design where only the topmost 50 m layer of the reservoir was open to production using 24×24 areal grids, rock matrix permeability of 5×10⁻¹⁴ m², and rock matrix porosity of 0.2%. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.7: 3D temperature contour from injection to production well after 25 years when all layers of the reservoir were open to production. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.8: 3D temperature contour from injection to production well after 25 years when only the topmost 50 m of the reservoir was open to production. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.9: Schematic diagram of the wellbore cross section.

Figure 5.10: CO₂ and H₂O based EGS mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.
Figure 5.11: CO\textsubscript{2} and H\textsubscript{2}O based EGS mass flow rates and heat extraction rates producing from only the topmost 50 m of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.12: CO\textsubscript{2} and H\textsubscript{2}O based EGS total exergy at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.13: Predicted CO\textsubscript{2} and H\textsubscript{2}O production wellhead temperature at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.14: Predicted CO\textsubscript{2} and H\textsubscript{2}O production wellhead pressure at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.15: Predicted CO\textsubscript{2} and H\textsubscript{2}O injection wellhead temperature at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.16: Predicted CO\textsubscript{2} and H\textsubscript{2}O injection wellhead pressure at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.17: CO\textsubscript{2} and H\textsubscript{2}O based power generation potential at production well design producing only from the topmost 50 m layer and producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure, 200°C reservoir temperature, and 20°C injection bottom-hole temperature.

Figure 5.18: Effect of injection bottom-hole temperature on CO\textsubscript{2} mass flow rates and heat extraction rates in production well design producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

Figure 5.19: Effect of injection bottom-hole temperature on CO\textsubscript{2} mass flow rates and heat extraction rates in production well design producing only from the topmost 50 m layer of the reservoir. Simulations were
conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

**Figure 5.20:** Effect of CO$_2$ injection bottom-hole temperature on CO$_2$ based EGS total exergy at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

**Figure 5.21:** CO$_2$ Effect of CO$_2$ injection bottom-hole temperature on CO$_2$ based EGS power generation potential at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

**Figure 5.22:** Effect of injection bottom-hole temperature on H$_2$O based EGS mass flow rates and heat extraction rates in production well design producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

**Figure 5.23:** Effect of injection bottom-hole temperature on H$_2$O based EGS mass flow rates and heat extraction rates in production well design producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

**Figure 5.24:** Effect of H$_2$O injection bottom-hole temperature on H$_2$O based EGS total exergy at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

**Figure 5.25:** Effect of H$_2$O injection bottom-hole temperature on H$_2$O based EGS power generation potential at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

**Figure 5.26:** Comparison of CO$_2$ and H$_2$O based EGS power generation potential at different injection bottom-hole temperatures. Simulations were conducted at 20 MPa reservoir pressure and 200°C reservoir temperature.

**Figure 5.27:** Effect of reservoir temperature on CO$_2$ mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

**Figure 5.28:** Effect of reservoir temperature on CO$_2$ mass flow rates and heat extraction rates producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.
Figure 5.29: CO$_2$ based EGS total exergy at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.30: CO$_2$ based EGS power generation potential at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.31: Effect of reservoir temperature on H$_2$O mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.32: Effect of reservoir temperature on H$_2$O mass flow rates and heat extraction rates producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.33: H$_2$O based EGS total exergy at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.34: H$_2$O based EGS power generation potentials at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.35: Comparison of CO$_2$ and H$_2$O based EGS power generation potential at different reservoir temperatures and at different reservoir-production well designs. Simulations were conducted at 20 MPa reservoir pressure and 20°C injection bottom-hole temperature.

Figure 5.36: Effect of reservoir pressure on CO$_2$ mass flow and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.37: Effect of reservoir pressure on CO$_2$ mass flow rates and heat extraction rates producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.38: CO$_2$ temperature-enthalpy diagram showing isobaric lines.

Figure 5.39: CO$_2$ based EGS total exergy at different reservoir pressure (depth) and different production well designs. Simulations were conducted at
200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.40: CO$_2$ based EGS power generation potential at different reservoir pressure (depth) and at different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.41: The predicted CO$_2$ production wellhead pressures at different reservoir pressures (depths) and different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.42: The predicted CO$_2$ injection wellhead pressures at different reservoir pressures (depths) and different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.43: CO$_2$ total pressure drop from injection to production wellhead at different reservoir pressures and at different production well designs. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.44: Effect of reservoir pressure on H$_2$O mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature and 20°C injection bottom-hole temperature.

Figure 5.45: Effect of reservoir pressure on H$_2$O mass flow rates and heat extraction rates producing only from the topmost 50 m layer of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.

Figure 5.46: H$_2$O temperature-enthalpy diagram showing isobaric lines.

Figure 5.47: Effect of rock matrix permeabilities on CO$_2$ mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.

Figure 5.48: Effect of rock matrix permeabilities on CO$_2$ mass flow rates and heat extraction rates producing from only the topmost 50 m layer of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.

Figure 5.49: Effect of rock matrix permeabilities on H$_2$O mass flow rates and heat extraction rates by producing from all layers of the reservoir. Simulations were conducted at 200°C reservoir temperature, 20 MPa reservoir pressure, and 20°C injection bottom-hole temperature.
Figure 5.50: Effect of rock matrix permeabilities on H\textsubscript{2}O mass flow rates and heat extraction rates by producing from only the topmost 50 m layer of the reservoir. Simulations were conducted at 200\textdegree C reservoir temperature, 20 MPa reservoir pressure, and 20\textdegree C injection bottom-hole temperature.

Figure 5.51: Effect of rock matrix permeability on CO\textsubscript{2} based EGS power generation potentials. Simulations were conducted at 200\textdegree C reservoir temperature, 20 MPa reservoir pressure, and 20\textdegree C injection bottom-hole temperature.

Figure 5.52: Effect of rock matrix permeability on H\textsubscript{2}O based EGS power generation potentials. Simulations were conducted at 200\textdegree C reservoir temperature, 20 MPa reservoir pressure, and 20\textdegree C injection bottom-hole temperature.

Figure 5.53: Comparison of CO\textsubscript{2} and H\textsubscript{2}O based EGS power generation potentials at 5\times10^{-15}m\textsuperscript{2} permeability and at different reservoir-production well designs. Simulations were conducted at 200\textdegree C reservoir temperature, 20 MPa reservoir pressure, and 20\textdegree C injection bottom-hole temperature.

Figure 5.54: Effect of rock matrix porosity on CO\textsubscript{2} mass flow rates and heat extraction rates producing from all layers of the reservoir. Simulations were conducted at 200\textdegree C reservoir temperature, 20 MPa reservoir pressure, and 20\textdegree C injection bottom-hole temperature.

Figure 5.55: CO\textsubscript{2} mass flow in the production well and heat extraction rates at different CO\textsubscript{2} constant mass flow rate injections. Simulations were conducted at 200\textdegree C reservoir temperature, 20 MPa reservoir pressure, and 25\textdegree C injection wellhead temperature.

Figure 5.56: Total exergy and power generation potential at different constant CO\textsubscript{2} mass flow rate injections. Simulations were conducted at 200\textdegree C reservoir temperature, 20 MPa reservoir pressure, and 25\textdegree C injection wellhead temperature.

Figure 5.57: Predicted CO\textsubscript{2} mass flow rates using a different number of spatial reservoir dimensions.

Figure 5.58: Predicted CO\textsubscript{2} heat extraction rates using a different number of spatial reservoir dimensions.

Figure 5.59: Predicted H\textsubscript{2}O mass flow rates using a different number of spatial reservoir dimensions.

Figure 5.60: Predicted H\textsubscript{2}O heat extraction rates using a different number of spatial reservoir dimensions.
Figure 5.61: CO₂ based EGS mass flow rates (secondary y-axis) and heat extraction rates when wellbore heat transport is considered (solid lines) and at adiabatic condition (broken lines).

Figure 5.62: CO₂ temperature profile at the injection well at different times and at adiabatic condition.

Figure 5.63: CO₂ density profile of the injection well at different times and at adiabatic condition.

Figure 5.64: CO₂ temperature profile of the production well at different times and at adiabatic condition.

Figure 5.65: CO₂ pressure profile of the production at different times and at adiabatic condition.

Figure 5.66: CO₂ based EGS heat extraction rates and power potential (secondary y-axis) when wellbore heat transport is considered (solid lines) and at adiabatic wellbore condition (broken lines).

Figure 5.67: CO₂ injection temperature and pressure (secondary y-axis) needed to maintain constant injection bottom-hole condition. The solid lines represent conditions with wellbore heat transport and the broken lines represent adiabatic wellbore flow.

Figure 5.68: CO₂ production temperature and pressure (secondary y-axis). The solid lines represent conditions with wellbore heat transport and the broken lines represent adiabatic wellbore flow.

Figure 5.69: H₂O-EGS heat extraction rates (left axis) and power potential (right axis) when wellbore heat transport is considered (solid lines) and at adiabatic wellbore condition (broken lines).

Figure 5.70: H₂O injection temperature and pressure (secondary y-axis) needed to maintain constant injection bottom-hole condition. The solid lines represent conditions with wellbore heat transport and the broken lines represent adiabatic wellbore flow.

Figure 5.71: H₂O production temperature and pressure (secondary y-axis). The solid lines represent conditions with wellbore heat transport and the broken lines represent adiabatic wellbore flow.

Figure 5.72: CO₂ and H₂O specific heat capacity profile in the production well when wellbore heat loss was considered after 10 years and at adiabatic condition.

Figure 6.1: The actual fluid-rock interaction apparatus. The high pressure pump in the picture was different from the one used during experiments.

Figure 6.2: Schematic diagram of the fluid-rock interaction apparatus.
Figure 6.3: Double ended rigid titanium reaction cell.

Figure 6.4: Moonbi granite outcrop, New England Highway, NSW, Australia.

Figure 6.5: Mossgiel drilling core section at 1793-1796 meter depth.

Figure 6.6: Nambucurra 1 drilling core section at 260.9-261.4 m.

Figure 6.7: Crushed samples (top) and the pulverised samples (bottom) inside the tungsten carbide ring mill.

Figure 6.8: Nambucurra 1 pulverised sample particle size distributions. The average particle size is 51.8 µm.

Figure 6.9: Moonbi pulverised sample particle size distributions. The average particle size is 16.1 µm.

Figure 6.10: Mossgiel pulverised sample particle size distributions. The average particle size is 5.7 µm.

Figure 6.11: Relative XRD trace of the three samples with ZnO internal standard, Nambucurra 1 (red), Moonbi (blue), and Mossgiel (green).

Figure 6.12: Relative XRD trace of the three samples without ZnO internal standard, Nambucurra 1 (red), Moonbi (blue), and Mossgiel (green).

Figure 6.13: Element concentration dissolved in supercritical CO₂ after 200°C and 35 MPa batch experiments.

Figure 6.14: Ruptured titanium reaction cell due to pre-mature depressurisation of the confining pressure.

Figure 6.15: Element compositions of the 2% nitric acid sample solutions taken from 200 °C and 20 MPa CO₂-rock interaction experiment using Moonbi pulverised granite.

Figure 6.16: Element compositions of the 2% nitric acid sample solutions taken from 250°C and 20 MPa CO₂-rock interaction experiment using the Moonbi pulverised granite.

Figure 6.17: Mutual Solubilities of H₂O and CO₂ as a function of pressure at 200 and 250°C. Source: Spycher & Pruess (2010).

Figure 6.18: The simulated aqueous Si concentration as function of temperature and calculated aqueous Si concentration in scCO₂ from CO₂-rock interaction batch experiments at different exposure times.

Figure 6.19: The simulated equilibrium log of aqueous (Na/K) ratio as function of temperature and the calculated log of aqueous (Na/K) ratio from the batch CO₂-rock interaction experiments.
Figure 6.20: The simulated equilibrium log of aqueous (Ca/Mg) ratio as function of temperature and the calculated log of aqueous (Ca/Mg) ratio from the batch CO$_2$-rock interaction experiments.  

Figure 6.21: Pulverised Moonbi granite before (left) and after the batch CO$_2$-rock interaction experiments.  

Figure 6.22: SEM images of the untreated pulverised Moonbi granite sample.  

Figure 6.23: SEM images of pulverised Moonbi granite after 23 days exposure in the batch CO$_2$-rock interaction experiments at 20 MPa and 200 °C.  

Figure 6.24: Average elemental Si concentration in the outlet fluid stream of the 20 MPa and 250°C flow-through experiments at different flow rates.  

Figure 6.25: Average elemental Na concentration in the outlet fluid stream of the 20 MPa and 250°C flow-through experiments at different flow rates.  

Figure 6.26: Average elemental K concentration in the outlet fluid stream of the 20 MPa and 250°C flow-through experiments at different flow rates.  

Figure 6.27: Average elemental Al concentration in the outlet fluid stream of the 20 MPa and 250°C flow-through experiments at different flow rates.  

Figure 6.28: Si concentration with time in the CO$_2$-rock interaction flow-through experiment at 0.50 ml CO$_2$/min (left axis, red circles) and the calculated water content in the CO$_2$ flow (right axis, blue diamond).  

Figure 6.29: Log of Na/K activity ratios with time in the outlet of the fluid stream from 20 MPA and 250°C flow-through experiments at different flow rates.  

Figure 6.30: Correlations of log of Na/K activity ratios (solid symbols) with the overall H$_2$O content in CO$_2$ flow (crossline symbols).  

Figure 6.31: The Giggenbach ternary diagram of the fluids reacted with Moonbi granite sample at 20 MPa and 250°C.  

Figure 6.32: The Si concentration of fluid samples from flow-through H$_2$O-rock interaction experiments and from that of Kuncoro et al. (2010) studies.  

Figure 6.33: Si, Na, K, and Al concentrations of the fluid samples from the flow-through experiments using granite from different sources. The H$_2$O content of the 0.20 ml/min fluid flow is shown at the bottom of the plot.  

Figure 6.34: The log of (Na/K) ratio of the fluid samples from the flow-through experiments using granite from different sources.  

Figure 6.35: Aqueous Ca, Mg, and Fe concentrations of the fluid samples from the flow-through experiments using granite from different sources.
Figure 6.36: Na-K-Mg ternary diagram of the fluid samples from the flow-through experiments using granite from different sources.

Figure 6.37: The XRD trace of the pulverised Moonbi granites before (blue line) and after batch reactions at different temperatures (green and red lines).

Figure 6.38: XRD trace of pulverised Moonbi granites before (green line) and after flow-through experiments at 20 MPa and 250°C using different CO$_2$ flow rates (brown and purple lines). The CO$_2$ streams contain up to 5% H$_2$O content.

Figure 6.39: XRD trace of pulverised Moonbi granites before (green line) and after flow-through experiments at 20 MPa and 250°C using different H$_2$O flow rates (orange and pink lines).

Figure 6.40: XRD trace of pulverised Moonbi granites before (blue line) and after flow-through experiments at 20 MPa and 250°C and 0.2ml/min CO$_2$ flow rate (green, pink and orange lines show the xrd trace of granites from different sections of the reactor). The CO$_2$ stream contains an average of 18.5% H$_2$O content.

Figure 6.41: SEM image of untreated (top) and treated (middle and bottom) Moonbi granite from 20 MPa and 250°C flow-through experiments.

Figure 6.42: XRD trace of pulverised Mossgeil granites before (blue line) and after flow-through experiments at 20 MPa and 250°C and 0.2ml/min CO$_2$ flow rate (green and red lines).

Figure 6.43: XRD trace of pulverised Nambucurra granites before (blue line) and after flow-through experiments at 20 MPa and 250°C and 0.2ml/min CO$_2$ flow rate (green and red lines).

Figure 6.44: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.20 ml CO$_2$/min flow Moonbi experiment.

Figure 6.45: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.50 ml CO$_2$/min flow Moonbi experiment.

Figure 6.46: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.20 ml H$_2$O/min flow Moonbi experiment.

Figure 6.47: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.05 ml H$_2$O/min flow Moonbi experiment.
Figure 6.48: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.20 ml CO$_2$/min flow Nambucurra experiment.

Figure 6.49: The actual inlet and back pressures, and temperature of the reactor (secondary y-axis) plotted against time from the 0.20 ml CO$_2$/min flow Mossgiel experiment.
List of Tables

Table 2.1: Research directly and indirectly related to CO$_2$ based EGS 34

Table 3.1: Maximum power output of single flash and dual flash steam cycles for given saturated liquid aquifer temperatures 50

Table 3.2: Theoretical maximum power output of an ORC using different organic fluids from 1 kg/s 250 °C saturated liquid aquifer fluid 53

Table 3.3: Log K temperature equation of some mineral dissolutions valid up to 300 °C and saturation pressure, modified after Angcoy(2010) 69

Table 4.1: Calculation parameters for 1D/2D EGS simulation 79

Table 4.2: Simulation inputs for the Power Cycle Modelling. 89

Table 5.1: Reservoir and injection/production parameters used in the 3D reservoir model simulations 147

Table 5.2: Input parameters used in the power cycle 148

Table 6.1: Major oxide compositions of the granite samples from AMDEL Limited fused bead XRF analytical results 221

Table 6.2: Major oxide compositions of the granite samples from The University of Newcastle fused bead XRF analytical results 221

Table 6.3: Mineral compositions of the granite samples in wt % based on quantitative XRD analysis 224

Table 6.4: Water content of the CO$_2$ in the batch CO$_2$-rock interaction experiments 232

Table 6.5: Major oxide compositions of untreated and treated pulverised Moonbi granite at 200°C and 20 MPa batch CO$_2$-rock interaction experiments 237
List of Publications

Remoroza, A.I., Moghtaderi, B., and Doroodchi, E. (2013, Feb 11-13). Fluid-Rock Interaction Experiments at Hot Dry Rock CO\textsubscript{2} Based Engineered Geothermal System Conditions. Abstract Accepted at the Thirty-Eighth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, USA.

Remoroza, A.I., Moghtaderi, B., and Doroodchi, E. (2012, Jan 30 - Feb 1). CO\textsubscript{2}-EGS In Hot Dry Rock: Preliminary Results From CO\textsubscript{2}-Rock Interaction Experiments. Paper presented at the Thirty-Seventh Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, USA.

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