Reducing operational costs of CO₂ sequestration through geothermal energy integration

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Keywords

Australia

Carbon storage

CCS flagship

Geothermal direct use

Energy integration

Electricity

Pressure management

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1. Abstract

Commercial scale Geological Carbon Storage (GCS) projects have high capital costs and energy penalties that could be partially offset by including the production of geothermal energy. An important requirement is to match the geothermal resources available at GCS sites with local market opportunities. This paper examines the key parameters that determine viable economics for various hybrid GCS-Geothermal energy applications with a focus on Australian GCS flagship sites as case study examples linked with the initial observations from a pilot trial at the SECARB Cranfield CO₂ demonstration project in Cranfield, Mississippi, USA. At first approximation, offshore GCS-geothermal coupling seems unlikely due to well costs and the additional engineering requirements. The Perth Basin provides the best opportunity for GCS-geothermal direct use for desalination. Whilst none of the case study examples would be ideally suited for GCS-Geothermal, insights gained are used to speculate on what conditions would be required for an economically viable opportunity. A strong enabling economic driver is when a GCS project already includes pressure relief water production as part of its base case.

2. Introduction

Geological Carbon Storage (GCS) has been identified as one of the important elements of greenhouse gas reduction strategies. Many of the technical aspects of carbon storage are well understood and for decades the oil and gas industry has injected into oil reservoirs as a method of enhancing recovery (Grigg, 2005). Large operations of this kind such as Weyburn (Whittaker et al. 2004), Cranfield (Meckel and Hovorka, 2009), and Rangely (Klusman, 2003) in the United States and Canada are monitored for reservoir and seal performance and storage conformance as case studies. While these commercial projects are useful case studies for understanding carbon storage processes in the subsurface, their primary business drivers are related to enhanced oil recovery, not carbon storage. In 1996, the world's first large-scale purely storage project was initiated by Statoil and its partners at the Sleipner Gas Field in the North Sea to remove CO₂ as part of its natural gas production operation. However by almost any measure, the subsequent uptake of commercial-scale carbon storage has underwhelmed predictions mainly due to the lack of a business case. Most new storage projects have remained at the research and pilot scale, for example, Otway (Jenkins et al. 2011).

In Australia, various studies (Grant et al. 2013, Cook 2012, Neal et al. 2010, Department of Resources, Energy and Tourism 2009, Gorgon Project in Western Australia) have suggested that the CO₂ storage cost is in the range of AUD\$4-\$36 per tonne avoided (saline aquifer storage) and AUD\$2-\$11 per tonne per 100km distance for transport with monitoring costs being negligible (IPCC 2005). The large range appropriately reflects the wide range of geological and geographical conditions for possible CO₂ injection projects. This can also be expected to be the case for storage costs across the world. All costs in this paper are converted to Australian Dollars in 2013 (base year). The current cost is likely to be slightly

lower compared to the literature data due to mainly the low oil price which drives the rig availability high and cost low, and also the technology development and growing knowledge of the subsurface in recent years. Even excluding capture cost, which in the case of the Oil and Gas (O&G) industry might be argued to already be a part of the core business, there is no current or historical price signal that would make carbon storage generally economically viable in almost any jurisdiction. In this paper, we examine if there is a realistic opportunity to improve the carbon storage business case by integrating a component of geothermal energy generation. We use Australia's planned carbon storage projects as a case study context.

3. Integrating Geothermal and Carbon Storage

While there are many different possible sources of geothermal energy (volcanic systems, Enhanced Geothermal Systems (EGS) or Hot Sedimentary Aquifers (HSA)), since most commercial scale carbon storage projects target sedimentary rocks at depths greater than 800m, we restrict ourselves to HSA type of geothermal resource applications. Since carbon storage requires suitable injectivity, capacity and containment as a prerequisite (IPCC 2005), there should generally be a good match of desirable rock properties for HSA. Figure 1 shows the location of Australia's planned carbon storage projects on the backdrop of the estimated temperature at 5km depth. This gives a first order indication of potential geothermal resources near planned carbon storage sites.

Geothermal energy is commonly harvested in two ways: electricity generation and direct utilisation. Conventional geothermal electric power production normally requires fluid temperatures around 98 °C or higher as low-temperature geothermal tends to be very inefficient with a strong dependence on heat rejection temperature, although selected examples were proved successful for as low as 74°C in Alaska depending on other site characteristics and business drivers. Direct utilisation in comparison, is possible from anything above seasonal surface temperature. A comparison between power generation and

direct-use geothermal options and the minimum production temperature requirements for various applications are presented in Table 1 and Figure 2 respectively. The sustainability of geothermal production over time in sedimentary basins is critically dependent of pressure support. Therefore, power and direct-use geothermal plants do not differ significantly, the working fluid is extracted from the reservoir to the surface, circulates within a heat exchanger and is then re-injected. The thermal energy is transferred from the reservoir working fluid to a secondary fluid. This secondary fluid is then used in a closed cycle (Figure 3a). In the case of geothermal coupled with GCS, the GCS can provide the pressure support and reinjection may not be required.

Direct Use

Direct use of geothermal energy can utilise a range of temperatures (depending on the application). Applications include district heating, bathing, agricultural drying, greenhouse heating (Lund et al. 1998 and 2011) and others (Figure 2). With 93.2% of the worldwide installed capacity specialized on residential applications (heat pumps, space heating, bathing and swimming; Lund et al., 2011) and most industrial uses of direct heat remain niche applications, which are also developed on a very site specific basis.

Italimpianti (2013) pointed out that low-enthalpy geothermal (below 150°C) is ideal for thermal desalination. Due to the nature of the process and the temperature available in the low-enthalpy geothermal energy, it is most cost effective to provide direct geothermal heat to a Multi-Effect Distillation (MED) plant (European Geothermal Energy Council).

Geothermal energy could be used to assist in coal drying, especially brown coal where the water content is high (50% to 60% in Victoria, Australia). Exergen's Continuous Hydrothermal De-watering (CHTD) process of brown coal reduces the moisture content in brown coal from 60-70% to 20-25% but operates at high temperature 300°C and 100 bar

(1450psi) (Exergen, 2014). A pre-drying stage might be considered using CO₂ or water at temperatures as low as 98°C (direct or indirect heat exchange) which could help reduce coal drying costs.

Some direct-use applications have a narrow working temperature window whereas others are widespread (Dickson and Fanelli, 2003). Therefore the sophistication employed in the temperature analysis and thermal characterization of the geothermal reservoir must match the flexibility/ complexity of the temperature requirements of the envisaged direct use application(s). The key in direct use applications is that the required use must be located near the source of the geothermal energy. Site specific evaluation is a requirement to identify direct use opportunities.

Power Generation

The binary cycle technology with Organic Rankine Cycle (ORC) and Kalina cycle appears to be the most efficient in comparison to dry steam, single and double flash steam plants for power generation (Zarrouk and Moon, 2014). They represent a convenient solution for resources with temperature lower than 150 °C. Binary power plants are generally preferred because of the fluid separation and the benefit of almost total re-injection (Di Pippo, 2008). They can also be modified to suit the specific working fluid and reservoir conditions (pressure, temperature, chemical composition and flow rate).

Electricity generation using low-temperature heat sources is generally characterized by relatively low conversion efficiencies (less than 10%). A current limitation of the power plants exists on the lower input temperature which is recorded at 86 °C in Australia (influenced by the high mean annual surface temperatures compared to colder climates). These working examples provide a context for the power that could be generated if, for

example, hot formation water were being produced to surface as part of a carbon storage pressure management scheme.

Two geothermal power plants have been developed in sedimentary basins in Australia. The first one at Mulka (South Australia), started in 1986 utilizing 86 °C water to produce 20 kWe (Popovsky, 2013). The second power plant in Birdsville (Queensland) benefits from 98 °C water to produce 150 kWe.

While power generation enables wider end use of the energy and transportation options, direct use geothermal applications provide better energy transfer efficiencies. Power generation efficiency of transferring heat energy into electricity from low temperature reservoirs is about 8 to 20 % (Zarrouk and Moon, 2014) while direct use energy efficiency can reach a coefficient of performance (ratio of electricity required to recover the heat to the net heat recovered) of as high as 39% (Pujol et al., 2015). Power generation is more suited to base-load grid-connected power supply while direct use projects have been applied more for localized residential and industrial applications which are subject to energy variation.

Coupling geological carbon storage and geothermal energy extraction

Geothermal energy systems can either use produced water or produced CO₂ as the working fluid. In the context of carbon storage projects, either can be pursued.

Initial research in coupling carbon dioxide sequestration with geothermal energy extraction focused on using supercritical CO₂ as the heat transmission fluid (Brown, 2000). Pruess (2006 and 2008) showed the larger expansivity and compressibility of CO₂ over water made it superior as the working fluid in hot fractured rock applications. Randolph (2011a and 2011b) followed by Salimi and Wolf (2012) presented modelling results demonstrating the calculated geothermal energy potential of a CO₂-based system and its potential economic and environmental benefits. Frank et al. (2012) applied life cycle analysis (LCA) for a coal-fired

power plant with carbon capture and storage facilities coupling geothermal power production with CO₂ as the working fluid and showed it to be beneficial. The difficulty with using CO₂ as the working fluid from a carbon storage reservoir is that the produced CO₂ will inevitably include a portion of formation water that makes the combined fluid corrosive.

More recently, Buscheck et al. (2013), Tillner et al., 2013 and Kempka et al, 2015 investigated the synergetic use of geological CO₂ storage and geothermal energy exploitation using formation water as the geothermal fluid. In this configuration, CO₂ injection acts as a pressure-support fluid to the geothermal production. Observations from projects solely for the purpose of carbon storage such as Snovit (Maldal and Tappel, 2004) and In Salah (Mathieson et al, 2011) would suggest that in certain geological circumstances, commercial-scale storage may require accompanying reservoir pressure management of some form. The Gorgon project that is in construction phase in north-western Australia, for example, includes formation water production as part of its planned pressure management options (Flett et al. 2009). Production of water as an integral part of the carbon storage operation provides an opportunity for utilising its contained heat. Buscheck et al. (2012) and Elliot et al. (2013) suggest that brine production can increase injectivity and be used to manipulate CO₂ migration. In the case of water production as pressure management, the water needs to either be utilised at surface, disposed of or reinjected into the subsurface but not into the GCS storage reservoir (Figure 3b). Alternatively, if CO₂ proves to be an economically superior working fluid, carbon storage reservoirs provide a ready source of heated CO₂.

4. Australian GCS opportunity for Combined Geothermal

In Australia, the Otway Project is the only project to have already injected CO₂ into the subsurface for storage; however, this is at Pilot-Scale with Stage 1 injecting just over 65,000 tonnes (Jenkins et al. 2012) and Stage 2B injecting on the order of 500 tonnes. However the Stage 2 test involved both injection and production of material from the well (Paterson et al., 2011). At the pilot scale there is no economic opportunity for combined GCS-Geothermal. The Chevron Gorgon Project in Western Australia is a ~US\$50Billion LNG development project that plans to inject on the order of 3.4-4.1 million tonnes/yr of CO₂ starting in 2015 (Smith et al., 2012) and includes the plan for water production pressure relief wells. However this commercial operation has limited public domain data available for analysis of its combined GCS-Geothermal potential. The remaining three active projects in Australia form part of the federal government's Carbon Capture and Storage Flagships Program. The GCS Flagships program was announced as part of the Australian Government's "Clean Energy Initiative" in May 2009. The program supports the demonstration of large-scale GCS projects in Australia. The projects participating or competing for funding in this program have included: South West Hub Carbon Capture and Storage Project (SW Hub) in Western Australia, Carbonnet in Victoria and the CTSCo-Wandoan project in Queensland. All of these projects are located in petroliferous sedimentary basins containing extensive public domain geological data.

To assess the potential for combined GCS-Geothermal, key information is required on the subsurface properties that may affect the economics of the geothermal component. These include the storage reservoir porosity and permeability, temperature, formation pressure, formation water salinity and the mean annual surface temperature. This information allows for a first order assessment of the potential temperature differential available at surface and the likely flow rate achievable. It should be noted that all three GCS Flagship projects are in

the site selection and characterisation phase so only the geographic region of the proposed project is known, not the detailed location of planned injection wells. We examined both public domain data housed in government databases and published information for the target injection formation for each proposed Australian carbon storage site. From this data we nominate an average depth representative of the proposed storage site, and estimate a representative set of key parameters from the available data. These are summarised in Table 2. It should be noted that the selected values presented in Table 2 have uncertainty due to geological heterogeneity and the fact that a final injection location for each site is yet to be selected. In particular, permeability values and to a lesser extent porosity can vary by several orders of magnitude over short distances. The values should be considered indicative only and are used to get a first order approximation of the geothermal energy potential at each site.

SW Hub

The SW Hub targets injection into the Wonnerup strata of the Lesueur Formation (Varma et al. 2009). Reservoir data was selected from public domain databases (e.g. WAPIMS (WADMP, 2014) and PressureDB (Hortle et al, 2013)) for a region of the Perth Basin near the selected site. The on-shore part of the Perth Basin near the SW Hub project area only has three legacy O&G exploration wells; however, extensive new data is available from the Harvey-1 data well drilled in 2012 as part of the SW Hub site characterisation. This data can also be supplemented by some deep (up to 800m) water monitoring bores. Several public domain reports are available on various rock property measurements of Harvey-1 and nearby Pinjara-1 cores including Evans (2012) and Delle Piane (2013). The Australian Government Bureau of Meteorology shows the SW Hub region mean high at 23°C and mean low at 14°C. Stalker et al. (2013) reported that a formation water sample was obtained from Harvey-1 that appeared contaminated by drilling fluid and estimates of formation water salinity in the

Wonnerup strata from petrophysical log analysis was presented by Varma et al. (2009). A summary of the estimated reservoir and fluid parameters are presented in Table 2.

CarbonNet

The Latrobe Group Strata form the major hydrocarbon reservoir in the offshore Gippsland Basin and multiple authors have examined its attributes together with the overlying Lakes Entrance seal for carbon storage potential (Michael et al. 2013, Varma et al. 2011, Goldie Divko et al, 2010, Gibson-Poole et al., 2008). A commonly suggested option is to target carbon storage under a mid-Latrobe intraformational seal and use the upper Latrobe and Lakes Entrance reservoir-seal pair as secondary capacity in an overall storage complex (e.g. Gibson-Poole et al., 2008). Since the CarbonNet project has yet to select a target site within its broad area of investigation, we use the substantial public domain O&G data in the offshore Gippsland basin (e.g. Geoscience Australia and PressureDB), and assess a region in the offshore for its geothermal energy potential that is likely to be representative of a carbon storage project. One might expect that an early mover project would try to minimise CO₂ transportation costs. For all data analysis we therefore examined both a regional data set as context and a highlighted subset representing a near-shore first injection option. Michael et al. (2013) modelled fluid flow in the Gippsland basin and assigned three different sand/siltstone rock types for the Latrobe strata: 1) permeability ~1 Darcy, porosity 20%, 2) permeability ~100 mD, porosity 20% and 3) permeability 0.1 mD, porosity 15%. The Australian Navy Metoc shows that the average annual sea temperature of the Gippsland coastal waters to be 16°C. The Bureau of Meteorology shows that the Gippsland coastal region mean annual surface air temperatures range between a mean high at 20°C and mean low at 8°C. The hydrodynamic flow systems of the Latrobe Strata of the Gippsland Basin have been reported on in the literature (Michael et al. 2013, Varma et al. 2011, Gibson-Poole

et al. 2008). Varma and Michael (2012) provide a detailed analysis of the Latrobe Group formation water chemistry that includes exploration and development well water sample data and petrophysical log analysis. Figure 4 summarizes the various data sets for the Latrobe strata of this region. We select a depth range of 2,000 to 3,000 m as an example of a mid-Latrobe near-shore target for carbon storage. The typical values of rock and fluid properties for this depth are summarized in Table 2.

CTSCo Wandoan

The Surat basin in Queensland has been the subject of evaluation for carbon storage potential with the Precipice and Showgrounds reservoirs identified to have storage potential (Bradshaw et al., 2009; Hodgkinson et al., 2009). The CTSCo-Wandoan project is located on the north-eastern flank of the Surat basin on the EPQ-7 greenhouse gas tenement. It is aiming to geologically store carbon in the fluvial dominated Precipice Formation beneath the lacustrine dominated Evergreen Formation top seal (Fielding, 1989, Green et al., 1997). A data well West Wandoan-1 was drilled on EPQ-7 in 2012 that provides a rich suite of modern data relevant to the permit area. Hussain et al. (2013) describes an overview of hydrodynamic properties of the Wandoan area. The Australian Government Bureau of Meteorology shows the CTSCo-Wandoan region mean high temperature at 27°C and mean low at 12°C (Dalby Airport). The salinity of the Precipice sandstone formation is reported to be fresh (<1000 mg/l) by many studies on Surat formation water chemistry (Grigorescu, 2011, Hodgkinson and Grigorescu, 2012, Haese et al., 2013a, 2013b). A summary of representative rock and fluid properties are shown in Table 2.

5. Cost Implications

In this section, we assess the additional costs and benefits relating to the potential geothermal applications that are suitable to the conditions of the Australian GCS Flagship Program locations. Costs include capital cost and Operating and Maintenance (O&M) cost for the additional facilities, equipment and in some circumstances even well(s) needed for the geothermal application, if not already required in the GCS project. The latter represents a major cost component which is heavily project specific and can vary substantially. Benefits are the cost savings from generating electricity or desalinating water for site or local usage. Due to the high variability of well costs, the payback period is not presented in this study. Time value of money is considered in this case, assuming average interest rate is 4%. It is assumed that GCS projects and geothermal power plants will operate for a 30-year period, whereas the desalination plants will operate for 20 years. Upon the 20th year, the desalination plants are renewed for another 20 years. The annual capacity factors for geothermal power plants and for desalination plants are 85% and 90% respectively. All costs are converted to 2013 Australian dollar in this study. Tables 3 to 5 are used as examples to demonstrate annualised cashflow for Victoria Organic Rankine Cycles with and without new wells, and seawater desalination plant without new wells respectively.

Several authors published their findings based on the desk-top research of techno-economic analysis for geothermal power plants, mostly overseas (Hance, 2005; Barnett and Quinlivan, 2009; Bromley et al, 2010; Cooper et al, 2010; Lovekin, 2000; Owens, 2002). Electric Power Research Institute (EPRI, Bedilion et al, 2009) reported on various electricity generation technology costs in an Australian context. Here we use the medium values of their suggested cost ranges (\$4,110/kW - \$7,310/kW for Hot Sedimentary Aquifer) for capital cost and O&M cost of geothermal power plant, \$5,710/kw and \$125/kW-yr respectively. It was estimated that the indicative capital cost for Birdsville geothermal power plant would be between

\$6,000/kW to \$7,000/kW including wells at a depth of 1230m (Queensland Government Environmental Protection Agency, 2005), which confirms that the cost of for EPRI case is ‘shallower drilling’ as is suggested in the paper. This indicates that in the case of CCS wells where the depths are significantly deeper as suggested in the previous section, well costs and ultimately geothermal power plant costs could be significantly higher.

For a typical binary Organic Rankine Cycle plant with installed capacity of 1 MWe and with the above assumptions in mind, this translates to AUD \$5.7 mil capital cost and AUD \$0.13 mil O&M cost per year. This includes an average cost of drilling onshore injection and production wells in the Eastern Australia, the cost of which we elaborate next. The generated electricity power, should it be utilised fully on site, results in energy and cost saving for the GCS project. Australian Energy Market Operator (AEMO, accessed on 21 August 2014) and Independent Market Operator (IMO, accessed on 30 March 2015) reported that the average costs (Regional Reference Price or RRP) of electricity in Queensland, Victoria and Western Australia in the period of 2010 to 2013 are \$42/MWh, \$37/MWh and \$44/MWh. This results in the profit of \$0.28 mil/yr (Victoria), \$0.31 mil/yr (Queensland) and \$0.33 mil/yr (WA) for a geothermal installed capacity of 1 MWe with 85% annual capacity factor.

Well costs can represent a major part of overall geothermal plant costs and varies significantly, depending on location and depth of the wells, reservoir fluid composition, casing material, rig availability, (which is often dependent on oil price), coexistence with other resources etc. Onshore wells in Surat/Bowen Basins at 1500m - 2000m cost below \$2 mil according to literature (Allinson et al., 2009; Garnett, A., Greig, C. and Oettinger, M., 2012 and Leamon, 2006). This figure will increase in the current market. In the Perth Basin, current wells cost around \$4.2 mil at 2000m – 3000m. At worst case scenario, offshore wells can cost over \$14 mil (Gippsland Basin, 2000m – 3000m) each. Depending on the existing facilities of the GCS project, at least one injection well and sometimes one production well

(for pressure relief) are already factored in the GCS project costs. This will take most of the capital cost away if no additional wells are required beyond those planned in the GCS projects. It will significantly improve the economy of the projects and shorten the payback time by at least 5 to 6 years.

For direct use applications, only a few projects have tested the feasibility of geothermal for seawater desalination, which include Milos Islands, Sousaki Korinthos and Nisyros in Greece. The case in Nisyros shows an indicative expenditure for MED geothermal desalination unit at capital cost of \$0.88 mil and operating and maintenance cost of \$0.25 mil/yr for the capacity of 300m³/day desalinated water produced (European Geothermal Energy Council). Similar costs are published by Abazza (2012) and Ophir and Lokiec (2004). Compared to standard municipal water supply desalination, the geothermal component saves \$3/m³ (Department of Energy and Water Supply 2014). The above assumptions take the payback period to 14 years in the first 20 years of the lifetime of the seawater desalination project. However, upon renewal of the desalination plant at the 20th year, the project immediately becomes non-economical for most of the remaining 10 years.

In general, the cost of desalinated seawater is 3 to 5 times of the cost of desalinated brackish water from the same size plant. If the MED process follows the same trend, it means a payback time as short as 6 years for a geothermal brackish plant. However, note that this analysis does not include the cost to drill additional wells. If production wells are required, the additional \$2 mil to \$4.2 mil capital costs itself would result in no payback within the 30-year life span of the project even for the lower salinity brackish water, not to mention the O&M costs related to the wells.

6. Risks and Uncertainties

The analysis of potential GCS-Geothermal opportunities so far did not consider key technical risks and uncertainties that underpin GCS-Geothermal operations. Despite the fact that there have been numerous techno-economic analysis of various GCS-Geothermal scenarios (Adams et al., 2015, Atrens et al., 2010), there has not yet been a single working physical demonstration to validate fundamental assumptions such as CO₂ producibility in a multiphase reservoir, heat and mass transfer in the wellbore system, and performance of surface equipment in handling real world mixtures of fluids which may include brine, methane, and wet gases.

In January 2015 our team performed a demonstration of the operation of a CO₂ thermosiphon to recover energy from the subsurface using a dipole well-pair at the site of the SECARB Cranfield CO₂ demonstration project in Cranfield, Mississippi, USA (Hovorka et al., 2013). This test is considered pre-commercial scale as the injector and producer well pair is separated by ~100 m. Hence thermal breakthrough of fluids would occur on time-scales that would not allow for cost-effective project development. Predictive models based upon the parameter sets developed for this heavily researched site were exercised using the T2Well simulator, which couples together the reservoir and wellbore to include heat transfer and fluid multiphase inertial terms in the wellbore/reservoir system (Pan and Oldenburg, 2012, Pan et al., 2015). While the data is still considered preliminary, flow rates observed and energy produced lagged predictions. In addition, water production in the models underestimated the actual water fraction recovered, which was produced in discrete slugs – a phenomenon not captured by the models.

While the implications of this experiment still await reduction of the field measurements, the initial observations are cautionary. The mobility contrast between super-critical CO₂ and brine is significant, and the basis for our understanding of brine/CO₂ relative permeability

and capillary pressure depends primarily on a limited number of studies conducted at the laboratory scale (Akbarabadi and Piri, 2013, Bachu 2013, Iglaue 2015). Extrapolating laboratory observations to heterogeneous field conditions is a challenge given the relative scarcity of field observations. To mature CO₂ geothermal technology and reduce uncertainty in the techno-economic analysis of coupled GCS/Geothermal will require field-scale testing in an assortment of lithologies under various reservoir conditions.

7. DISCUSSION

An outcome of coupling GCS and geothermal is the requirement for matching geothermal resources with local market opportunities. A GCS project might have limited direct use geothermal market opportunities by itself but will require electrical power. At the same time, geothermal power generation is likely to address more adequately the diverse needs of the GCS project but also can be transported further away with less losses. One of the drawbacks of power generation is that depending on the plant size, power generation for geothermal energy might not be economically competitive compared to other electricity sources and existing infrastructure.

If the resource is not suitable for geothermal power generation, a GCS project might have limited direct use geothermal market opportunities by itself. Due to the intrinsic localised nature of direct use, the practical application of a GCS-direct use coupling is highly dependent on the direct-use needs of the GCS project or by extension to the market in the vicinity. While direct use has been extensively developed for residential uses, the industrial processes application are still limited and confined to niche activities. The cost of transporting hot water with associated heat losses will impose limitations on the direct-use opportunities beyond the immediate vicinity of the GCS plant. With limited direct use applications for industrial processes (Lund et al, 2011), developing a coupling GCS-geothermal coupling is a challenging engineering task. An important economic advantage of

GCS-geothermal coupling is achieved when the GCS project already includes a pressure management plan with water production and utilisation or disposal. In fact this aspect appears to be a critical economic enabler of combined Geothermal-GCS viability. This is because the well costs play a major role in the overall cost and feasibility of coupling. If the pressure relief wells are already planned in the GCS project, the cost balance is in favour of coupling in most cases where adequate geothermal temperature is available. However if additional wells are required for the Geothermal component of a GCS operation, this significantly disadvantages all scenario economics. The extent of this economic disadvantage depends on the actual project specific well costs, but for the Australian case examples where at least 19 years payback time is required for a 30-year project (Organic Rankine Cycle, Western Australia), none of the scenarios were economically viable where new wells are required to be drilled.

We examined a number of possible geothermal applications that might be employed to offset GSC operational costs. For example, within a brown coal power station, drying of the coal and heat integration in the CO₂ capture plant might be viable options under certain circumstances where the plant locations are adjacent to the sequestration sites. They need to be assessed carefully on a case by case basis and realistic co-location opportunities will be rare. We conclude that the best opportunities for economically viable GSC-Geothermal will either be for geothermal power generation or direct use geothermal water desalination. In both cases, the economics become favourable if the GCS project has a requirement of pressure maintenance and is already producing hot water to surface for utilisation or disposal as part of the GCS business case.

For the Australian context summarised in Table 2, the Gippsland Basin has the most favourable geological properties for capturing geothermal energy compared to the Perth and Surat basins due to higher temperature and permeability. With the reservoir temperature close

to 98°C, the geothermal energy on site could be potentially converted into electricity using a binary Organic Rankine Cycle plant and offset the power requirement in the GCS plants. Since pressure maintenance is not anticipated to be required, the additional well costs mean that it will likely take most of a 30-year carbon storage project to reach break-even point for the capital and maintenance investment. This would be an ideal scenario without any real world contingencies. As the site locations for GCS are most probably offshore, energy will be needed to supply the GCS plants. This provides both opportunity and challenge for geothermal power. Whilst geothermal power could help offset GCS operational requirements, the space limitations of operations from an off-shore platform would likely preclude on-site geothermal power generation.

For the Perth and Surat basins, with slightly lower temperatures available, MED desalination plants would be the most promising available option for geothermal energy integration. Yet this integration option takes almost the entire lifetime for a new built MED geothermal seawater desalination plant to reach break-even point, again without any real world contingencies. However, if desalination of water less saline than seawater is required, then break-even can be significantly shortened which makes the integration more attractive. The Surat basin has sufficiently high permeability that pressure maintenance will not be required, however the SW Hub is likely to require pressure maintenance via brackish water production. Here the geothermal energy could be used to desalinate the produced water for local agricultural application or municipal water supply. The question remains if there would be sufficient brackish water supply to make this viable.

In the Perth basin there is an existing seawater desalination plant near Binningup that delivers water to the Perth metropolitan area municipal water supply. In addition, the relatively low permeability of the Wonnerup GCS reservoir may require pressure relief wells as part of the core carbon storage project. Retrofitting existing desalination plants to geothermal is not

feasible as they have a different equipment requirement compared to MED. However with the growing population of the Perth metropolitan area, and as more desalination capacity becomes required, new desalination plant could be constructed to take advantage of combined GCS-Geothermal technology.

All examined options for combined GCS-Geothermal applications at Australian CS Flagship sites remain economically marginal (Table 6). With the lack of compelling economically feasible opportunities for combined GCS- Geothermal at Australia's GCS flagship demonstration sites, it is worth considering the conditions that are required to make other GCS project amenable to geothermal synergies. The ideal GCS-geothermal coupling will probably look like a GCS project in an onshore remote area (where the levelized cost of electricity – LCOE – is high) with a geothermal resource higher than 98 °C with a requirement for pressure maintenance, co-located with electricity demand.

Limited public information on the Chevron Barrow Island GCS project reveals that multiple pressure relief wells are anticipated to produce water from the storage reservoir and the reservoir temperature is ~100 °C. The produced water will likely be re-injected at another stratigraphic level. Although locally generated geothermal power on Barrow Island would be beneficial where LCOE is high, the temperature available is likely to still be economically marginal.

A more holistic approach would be to search for opportunities to site a GCS project that also optimises the geothermal energy offset potential. One example may be the Moomba Carbon Storage project proposed by Santos in depleted oil and gas reservoirs of the Cooper basin in South Australia (Santos, 2014). Here, Middleton (1979) used corrected bottom hole temperatures to estimate heat flow at the Moomba and Big Lake fields to be 2.6 microcal/cm² sec °C and Gallagher (1988) described a regional geothermal gradient being up to 40 °C/km.

In the region around Moomba, the Tirrawarra and Patchawarra reservoirs range from 1900 to 2300m deep with formation temperatures of 134 to 141 °C (Gravestock et al. 1998). Co-location of GCS at Moomba that already has extensive oil and gas production facilities, a high in situ temperature and at a remote location with power requirements, has the highest economic viability for combined GCS-Geothermal application.

8. CONCLUSION

For this investigation, we have examined the range of possible geothermal energy opportunities (both power generation and direct use) that could be co-located with a GCS project to effectively offset cost. We examined the key parameters such as temperature differential and permeability that determine viable economics for various geothermal energy applications. We then reviewed data from Australian GCS Flagship projects as case study examples for combined geothermal-GCS potential. As part of the GCS-geothermal coupling evaluation, we identified the geothermal market opportunities in relation to electricity and co-localized direct use opportunities, characterized the resource for electricity generation and evaluated possible off-sets by the GCS project for the geothermal coupling component.

In general, combined GCS-Geothermal concept for the Australian flagship GCS project case studies is likely to be economically marginal at best. We conclude the following:

- At first approximation, offshore GCS-geothermal coupling seems unlikely due to well costs and the added engineering required for a platform to accommodate the geothermal component in a situation of limited footprint requirements.
- The Perth basin provides the best opportunity for GCS-Geothermal direct use for desalination and beneficial re-use of produced water. This is due to the likelihood for GCS pressure maintenance requirements and an increasing demand for water

resources in the Perth region already partially reliant on desalination. The produced brackish water could be desalinated and used in the local water supply infrastructure.

More generic global applications are most likely to be economic where:

- The GCS project is using water production as a form of pressure management with water utilisation or disposal and no additional wells are required for the Geothermal component
- Produced water is greater than 150 °C and is located in a cold climate region
- The GCS project is near power transmission lines.

ACKNOWLEDGEMENT

The authors wish to acknowledge financial assistance provided through Australian National Low Emissions Coal Research and Development (ANLEC R&D). ANLEC R&D is supported by Australian Coal Association Low Emissions Technology Limited and the Australian Government through the Clean Energy Initiative.

Funding for Lawrence Berkeley National Lab and the SECARB Cranfield research has been provided by the Assistant Secretary for Energy Efficiency and Renewable Energy, Geothermal Technologies Program of the U.S. Department of Energy under Contract No. DE-AC0205CH11231.

ABBREVIATIONS

AEMO: Australian Energy Market Operator

EGS: Enhanced Geothermal System

GCS: Geological Carbon Storage

HSA: Hot Sedimentary Aquifer

IMO: Independent Market Operator

LCA: Life Cycle Analysis

O&G: Oil and Gas

O&M costs: Operating and Maintenance costs

ORC: Organic Rankine cycle

RRP: Regional Reference Price

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TABLES

Table 1. High level comparison of power generation and direct use geothermal applications

Table 2 Key subsurface properties for three Australian GCS sites

Table 3 Cash flow for Organic Rankine Cycle plants integrating into GCS projects (new wells required, Victoria)

Table 4 Cash flow for Organic Rankine Cycle plants integrating into GCS projects (existing wells, Victoria)

Table 5 Cash flow for desalination plants integrating into GCS projects (seawater, existing wells)

Table 6 Cost implication for geothermal integration with GCS projects

	Power generation	Direct use applications
Efficiency	<i>Low efficiency</i>	<i>High efficiency</i>
Usage	<i>Wide usage (electricity)</i>	<i>Specific use</i>
Transport	<i>can be transported</i>	<i>Need to be used locally</i>
Flexibility on resources	<i>Depend on the surface facility and its requirements on working temperature and flow rate fluctuations and evolution over the project lifetime</i>	
Flexibility on demand	<i>Depend on the energy demand</i>	
Energy supplied	<i>kWe</i>	<i>MWth</i>
Minimum Temperature (°C)	<i>98</i>	<i>30</i>

Australian Basins	Gippsland	Perth	Surat
Depth	<i>2000m – 3000m</i>	<i>2500m</i>	<i>1250m</i>
Temperature	<i>98°C</i>	<i>69°C</i>	<i>65°C</i>
Permeability	<i>500mD</i>	<i>50mD</i>	<i>500mD</i>
Porosity	<i>28%</i>	<i>19%</i>	<i>22%</i>
Salinity	<i>35,000 mg/l</i>	<i>30,000 mg/l</i>	<i>500mg/l</i>
Formation Pressure	<i>3490psi</i>	<i>3598psi</i>	<i>1790psi</i>
Pressure Maintenance Requirement	<i>Not required</i>	<i>May be required</i>	<i>Not required</i>
Location	<i>Off-shore</i>	<i>On-shore</i>	<i>On-shore</i>

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Capital Cost (mil)	-5.7															
O&M Cost (mil)		-0.14	-0.14	-0.15	-0.15	-0.16	-0.16	-0.17	-0.18	-0.19	-0.19	-0.20	-0.21	-0.22	-0.23	-0.23
Profit (mil)		0.29	0.30	0.31	0.33	0.34	0.35	0.37	0.38	0.40	0.41	0.43	0.45	0.47	0.48	0.50
NPV (mil)		-5.54	-5.38	-5.21	-5.04	-4.86	-4.67	-4.47	-4.26	-4.05	-3.83	-3.60	-3.36	-3.11	-2.85	-2.58
		Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
Capital Cost (mil)																
O&M Cost (mil)		-0.24	-0.25	-0.26	-0.27	-0.28	-0.30	-0.31	-0.32	-0.33	-0.35	-0.36	-0.37	-0.39	-0.41	-0.42
Profit (mil)		0.52	0.55	0.57	0.59	0.61	0.64	0.66	0.69	0.72	0.75	0.78	0.81	0.84	0.87	0.91
NPV (mil)		-2.30	-2.00	-1.70	-1.38	-1.05	-0.71	-0.36	0.01	0.40	0.80	1.21	1.65	2.09	2.56	3.05

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Capital Cost (mil)	-3.7															
O&M Cost (mil)		-0.14	-0.14	-0.15	-0.15	-0.16	-0.16	-0.17	-0.18	-0.19	-0.19	-0.20	-0.21	-0.22	-0.23	-0.23
Profit (mil)		0.29	0.30	0.31	0.33	0.34	0.35	0.37	0.38	0.40	0.41	0.43	0.45	0.47	0.48	0.50
NPV (mil)		-3.54	-3.38	-3.21	-3.04	-2.86	-2.67	-2.47	-2.26	-2.05	-1.83	-1.60	-1.36	-1.11	-0.85	-0.58
		Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
Capital Cost (mil)																
O&M Cost (mil)		-0.24	-0.25	-0.26	-0.27	-0.28	-0.30	-0.31	-0.32	-0.33	-0.35	-0.36	-0.37	-0.39	-0.41	-0.42
Profit (mil)		0.52	0.55	0.57	0.59	0.61	0.64	0.66	0.69	0.72	0.75	0.78	0.81	0.84	0.87	0.91
NPV (mil)		-0.30	0.00	0.30	0.62	0.95	1.29	1.64	2.01	2.40	2.80	3.21	3.65	4.09	4.56	5.05

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Capital Cost (mil)	-0.88															
O&M Cost (mil)		-0.26	-0.27	-0.28	-0.29	-0.30	-0.31	-0.32	-0.34	-0.35	-0.36	-0.38	-0.39	-0.41	-0.42	-0.44
Profit (mil)		0.31	0.32	0.33	0.35	0.36	0.37	0.39	0.40	0.42	0.44	0.46	0.47	0.49	0.51	0.53
NPV (mil)		-0.83	-0.78	-0.72	-0.66	-0.60	-0.54	-0.47	-0.40	-0.33	-0.26	-0.18	-0.10	-0.02	0.07	0.16
		Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
Capital Cost (mil)						-1.94										
O&M Cost (mil)		-0.46	-0.48	-0.50	-0.52	-0.54	-0.56	-0.58	-0.60	-0.63	-0.65	-0.68	-0.71	-0.74	-0.77	-0.80
Profit (mil)		0.55	0.58	0.60	0.62	0.65	0.67	0.70	0.73	0.76	0.79	0.82	0.85	0.89	0.92	0.96
NPV (mil)		0.26	0.35	0.46	0.56	-1.27	-1.15	-1.03	-0.91	-0.78	-0.65	-0.51	-0.36	-0.21	-0.05	0.11

	Electricity Generation (ORC)		Direct Use Application (Desalination)		
	New Wells Required	Existing Wells	Existing Wells - Seawater	Existing Wells – Brackish Water	New Wells Required – Brackish Water
Capacity	<i>1 MWe</i>	<i>1 MWe</i>	<i>300 m³/day</i>	<i>300 m³/day</i>	<i>300 m³/day</i>
Capital Cost (mil)	<i>5.7</i>	<i>3.7</i>	<i>0.88</i>	<i>0.29</i>	<i>2.29</i>
O&M Cost (mil)	<i>0.13/yr</i>	<i>0.13/yr</i>	<i>0.25/yr</i>	<i>0.25/yr</i>	<i>0.25/yr</i>
Profit (mil)	<i>0.28-0.33</i>	<i>0.28-0.33</i>	<i>0.3</i>	<i>0.3</i>	<i>0.3</i>
NPV (mil)	<i>3.05-5.97</i>	<i>5.05-7.97</i>	<i>0.11</i>	<i>1.99</i>	<i>-0.01</i>
Payback time (yrs)	<i>19-23</i>	<i>14-17</i>	<i>23</i>	<i>6</i>	<i>>30</i>

1 **FIGURES**

2 **Figure 1 Location of Carbon geological storage investigation (Black dots), geothermal**
3 **power plants (green dots) and predicted temperature at 5km depth, adapted from**
4 **Geoscience Australia, 2007.**

5 **Figure 2 Possible applications of geothermal energy suggested by Lindal (1973), as cited**
6 **by Fridleifsson (1998).**

7 **Figure 3. Conceptual scheme of geothermal power generation with binary cycle and a**
8 **doublet production-injection wells.**

9 **Figure 4. Gippsland basin reservoir dataset from PressureDB – (A) Permeability vs**
10 **Depth (available –black square- and selected –green square- range), (B) Permeability vs**
11 **Porosity, (C) Temperature vs. Depth and (D) Pressure vs Depth. For a reservoir**
12 **between 2,000 and 3,000m depth, the permeability varies between 100 and 1,000 mD,**
13 **the porosity between 15 to 37 %, the temperature range is from 80 to 120 °C and the**
14 **pressure is close to hydrostatic pressure with slightly under-pressure of 50m head.**

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