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Opportunities for increasing CO_2 storage in deep, saline formations by active reservoir management and treatment of extracted formation water: Case study at the GreenGen IGCC facility, Tianjin, PR China

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ABSTRACT

Carbon capture, utilization and storage (CCUS) seeks beneficial applications for CO_2 recovered from fossil fuel combustion. This study evaluated the potential for removing formation water to create additional storage capacity for CO_2, while simultaneously treating the produced water for beneficial use. The process would control pressures within the target formation, lessen the risk of caprock failure, and better control the movement of CO_2 within that formation. The project plans to highlight the method of using individual wells to produce formation water prior to injecting CO_2 as an efficient means of managing reservoir pressure. Because the pressure drawdown resulting from pre-injection formation water production will inversely correlate with pressure buildup resulting from CO_2 injection, it can be proactively used to estimate CO_2 storage capacity and to plan well-field operations. The project studied the GreenGen site in Tianjin, China where Huaneng Corporation is capturing CO_2 at a coal fired IGCC power plant. Known as the Tianjin Enhanced Water Recovery (EWR) project, local rock units were evaluated for CO_2 storage potential and produced water treatment options were then developed. Average treatment cost for produced water with a cooling water treatment goal ranged from 2.27 to 2.96 US\$/m^3 (recovery 95.25%), and for a boiler water treatment goal ranged from 2.37 to 3.18 US\$/m^3 (recovery 92.78%). Importance analysis indicated that water quality parameters and transportation are significant cost factors as the injection-extraction system is managed over time. The study found that in a broad sense, active reservoir management in the context of CCUS/EWR is technically feasible. In addition, criteria for evaluating suitable vs. unsuitable reservoir properties, reservoir storage (caprock) integrity, a recommended injection/withdrawal strategy and cost estimates for water treatment and reservoir management are proposed.

1. Introduction

Capture, utilization, and storage of carbon dioxide (CO_2) from fossil fuel combustion is a key element in the global imperative to control greenhouse gasses (Middleton et al., 2015). Currently, intensive development of coal resources around the world is leading to large increases in CO_2 emissions (Stauffer et al., 2011). To address concerns over steadily increasing concentrations of atmospheric CO_2, the United States and China have joined forces to collaborate on developing new clean energy technologies. This collaboration, the US-China Clean Energy Research Center (CERC), was originally established as a 5 year venture in November 2009 and was recently renewed for an additional five year term (CERC, 2015). One of the three primary thrusts of this collaboration is the Advanced Coal Technology Consortium (ACTC), tasked with finding new ways to bring coal into the 21st century by reducing its environmental and societal impacts (CERC-ACTC, 2015). As part of the CERC-ACTC, our team is working with Chinese collaborators to find new ways to reduce emissions by diverting coal-generated CO_2 toward utilization and storage in subsurface applications. Car-

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bon capture, utilization and storage (CCUS) seeks beneficial uses for captured CO_2 while simultaneously reducing atmospheric loading. A well-known example of such an application is enhanced oil recovery (EOR), where CO_2 is used to increase oil production while at the same time storing CO_2 in subsurface reservoirs (Luo et al., 2014). In the following study, we describe a new example of how CO_2 can be utilized to enhance water production and treatment for beneficial use.

Specifically, this pre-feasibility study evaluates the potential for removing water from a saline reservoir to create additional storage capacity for CO_2, while treating the produced water so that it can be used for industrial applications. Fluid injection methods such as water flooding have been widely practiced in petroleum reservoirs to optimize resource recovery (Phade and Gupta, 2008). CO_2 injection for enhanced oil recovery is also widely practiced in the U.S.; an excellent summary is provided by Meyer (American Petroleum Institute, 2007). Production of water to control pressure, and to better constrain CO_2 movement within the target formation, is known as active reservoir management, a process that reduces risks associated with induced seismicity, fracturing, and leakage (Buscheck et al., 2011, 2012). The second half of the process, treating formation water and using the water, is termed enhanced water recovery (EWR) as a parallel application to EOR.

In active management, produced formation waters are brought to the surface and treated to supplement agricultural, municipal use, or industrial process water. Additionally, these waters can be the source of valuable chemicals that can be used to off-set costs related to CO_2 injection (Mining, 2013). Because of the scale of CO_2 generation from coal and other sources, significant volumes of treated water may be made available. It is expected that a cubic meter of water would be produced for each cubic meter of injected supercritical CO_2 (Middleton et al., 2012). In the range of pressures and temperatures found in sites that have been considered for CCUS, density of CO_2 ranges from about half that of formation water to nearly equal to formation water at low temperature and high pressure (Middleton et al., 2012). Treatment of brackish and saline formation waters to industrial, agricultural, or human use standards is well understood, although the optimal treatment train for a specific water type and its associated cost should be based on the logistics and chemistry of the specific formation water of interest. Finally, desalination processes generate concentrated (i.e. residual) brines or salt cakes requiring disposal, an important cost factor to consider in the analysis of a complete system.

Besides using separate injection and production wells, active management can also be implemented using a pre-injection formation-water production strategy with the same well being used to produce water before injecting CO_2 (Buscheck et al., 2014, 2016a,b). This approach can make more efficient use of the wells because pressure drawdown is centered where pressure buildup due to CO_2 injection will subsequently occur. This approach can be nearly 100% effective on a volume-per-volume formation water removal basis—for each cubic meter of water removed, nearly an additional cubic meter of CO_2 can be injected with the same overpressure (defined to be pressure in excess of ambient) outcome (Buscheck et al., 2016a). Because the pressure drawdown from pre-injection water production inversely correlates with pressure buildup that will result from CO_2 injection, it generates data that can be proactively used to estimate CO_2 storage capacity and to plan well-field operations before any CO_2 is injected (Buscheck et al., 2016a,b). As discussed later in this paper, these benefits can reduce project cost and risk.

Evaluation of reservoir management and EWR requires knowledge of critical reservoir conditions and the assurance that the planned CO_2 storage volumes and injection rates are achievable. Several fundamental assumptions are involved:

- Reliable estimation of reservoir injectivity and capacity is possible.
- Adequate hydraulic conductivity throughout the reservoir.
- CO_2, formation waters or brines and reject waters or brines will not form scale/precipitates and interfere with reservoir conductivity.
- Withdrawal of formation brines will increase effective CO_2 storage capacity.
- The selected water treatment strategy will meet technical and financial expectations.

Our work focuses on the GreenGen site in Tianjin, China where the China Huaneng Group is leading efforts to capture CO_2 at a coal-fired Integrated Gasification Combined Cycle (IGCC) power plant. The target injection reservoirs (Neogene Guantao (Ng) and Paleogene Dongying (Ed) formations) within the Qikou Sag of the larger Bohai Bay Basin are at depths between 1500–2500 m and are saturated with brackish formation water in the range of 700–16,000 mg/L total dissolved solids (TDS). Based on analysis of numerous wells in the area, the relatively low salinity and sufficient depth to achieve supercritical CO_2 conditions, these formations received positive recommendations related to geologic CO_2 storage from Yang et al. (2013). The immediate objective of this work is to provide the GreenGen project with an initial evaluation of reservoir management and EWR/water treatment options to lessen uncertainty prior to finalizing project designs. This process is expected to be widely applicable in many candidate CO_2 storage reservoirs.

In the following paper, we first describe the geologic setting and present properties of the rock units in the vicinity of the GreenGen plant. Next, we evaluate the likely reservoir performance of the Guantao and Donying formations with respect to CO_2 injectivity and plume spreading using a system analysis tool. Following this, a plan for active reservoir management is described including calculations of reduced pressure impacts associated with water removal from the targeted injection horizons. Treatment options are then identified for the produced water, with uncertainty analysis around key parameters such as salinity and temperature. Finally, a discussion of interactions between active reservoir management and water treatment is presented.

2. Site description

2.1. The geological setting

The Bohai Bay Basin in eastern coastal China was examined for a CO_2 storage resource assessment south of Tianjin in the immediate vicinity of the Huaneng GreenGen IGCC facility in Binhai New Area near Tanggu (Fig. 1a). This is a Mesozoic–Cenozoic rifted sedimentary basin consisting of a series of fault-bounded sub-basins (sags) filled by thick continental Paleogene (Eocene), clastic sediments (Fig. 1b). A regional unconformity at the top of the syn-rift sediments separates Paleogene and older sediments from Neogene to recent strata, which were deposited during post-rift thermal subsidence. Major faults form Paleogene half-graben and growth-fault structures and relative uplifts (heaves) that define smaller subbasins (sags) in the north-central portion of the basin. Faulting related to post-rift thermal subsidence continues in the Neogene and may reach to the present day surface (Zhou et al., 2012).

The regional stratigraphy, from the top to the bottom, consists of basin-wide continental sandstone and clay Quaternary sediments (250–550 m thick) that are underlain by the Neogene continental post-rift interbedded sandstone and mudstone beds of the Minghuazhen Formation (230–1300 m thick). The numerous interbedded mudstone units of the Minghuazhen (Nm) stretch across the entire basin and are assumed to form multiple regional

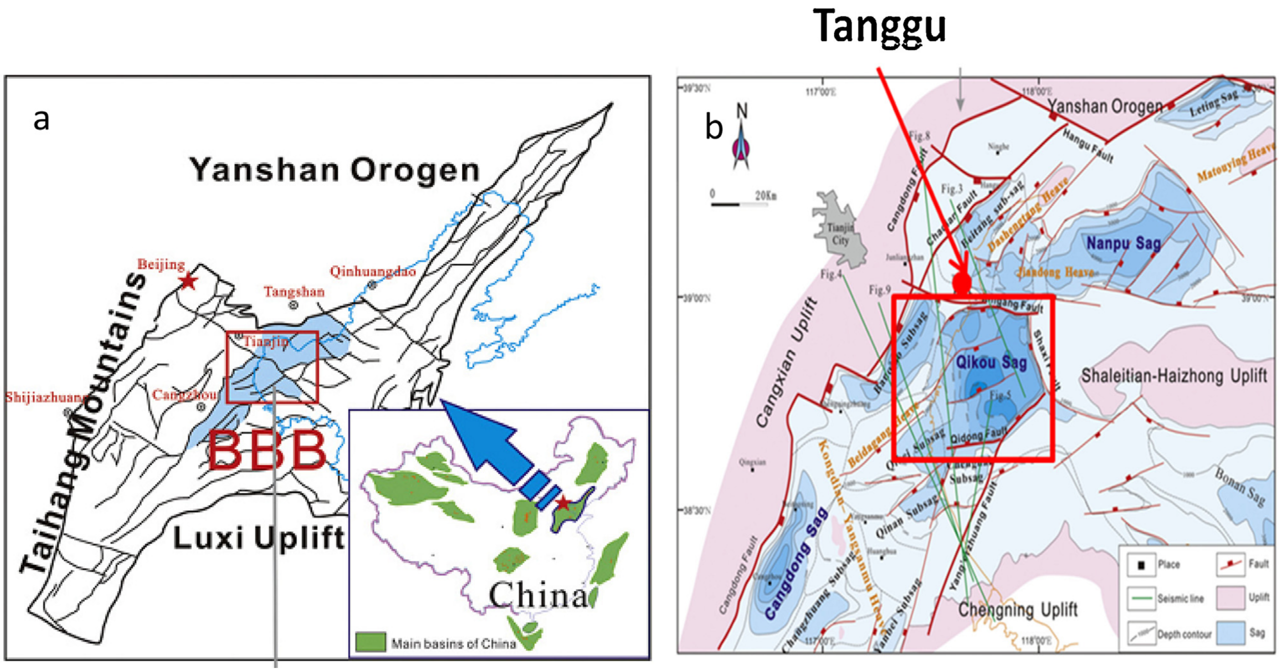

Fig. 1. (a) Location and structural framework of the Bohai Bay Basin in eastern coastal China with highlighted study area south-east of Tianjin. (b) Structural framework of the study area in the immediate vicinity of the Huaneng GreenGen IGCC facility in Binhai New Area near Tanggu. Modified from Zhou et al. (2012).

seals (Yang et al., 2013). The lower portion of the Minghuazhen is dominated by mudstone, inter-layered with fine-grained sandstone, and is considered the primary regional seal for containment. The underlying post-rift Neogene Guantao Formation (Ng) is widely distributed across the basin but thins and can be absent on structural highs (0–1520 m thick). The Guantao consists of sandstone inter-layered with poorly sorted pebbly sandstone inter-layered with mudstone toward the base. The Guantao is characterized by relatively low salinity water (<10,000 mg/L TDS) and high porosity and permeability. For comparison, the TDS of average sea water is about 35,000 mg/L. The Neogene is separated by a regional unconformity from the Paleogene syn-rift units. The uppermost unit, the Eocene Dongying Formation (Ed) (0–400 m) is a heterogeneous unit consisting of sandstone, mudstone, oil shale and limestone that thickens near bounding faults of sags. Salinity increases in the Dongying Formation, but remains relatively low and fluid pressure remains at hydrostatic (Fig. 2). Porosity and permeability in the sandstone units of the Dongying can be very high especially along faults bounding sags. These, and form numerous hydrocarbon reservoirs characteristic of the Bohai Bay Basin. The predominance of normal faulting indicates that relative regional stress condition is Sv > SHmax > SHmin. The numerous relatively small hydrocarbon fields with liquid production suggest a significant degree of heterogeneity, but porosity and permeability is sufficient for CO_2 injection. If additional well data can be obtained, the next step would be to quantify local reservoir quality and local stress conditions.

2.1.1. Guantao CO_2 storage reservoir properties

The base of the Neogene Guantao Formation, a target CO_2 storage horizon, is composed of sandstone, sandy gravel and gravel. The sandstone units consist of quartz, feldspar (including albite and anorthite), montmorillonite, illite, kaolinite and minor chlorite (Pang et al., 2012). Based on reported data, the permeability of sandstone in the Guantao Formation varies from 800 to 2000 mD, while the porosity is 18–38% (Hu, 2002; Pang et al., 2012; Yang et al., 2013).

Water samples from the Guantao and related Neogene formations have reported salinities of 800–1000 mg/L, and are of HCO_3-Cl-Na or Cl-HCO_3–Na types (Pang et al., 2012; Yang et al., 2013). Water pH determined in situ indicates that the water is neutral to alkaline with an average pH of 7.7 (Pang et al., 2012). Based on the analysis of sonic travel time, pressure gradient appears to be hydrostatic until below the first member of the Shahejie Formation (Fig. 2).

2.1.2. Dongying CO_2 storage reservoir properties

Beneath the regional unconformity, the Dongying Formation was deposited during the waning stage of rifting and shows a coursing upward trend from fine grained rocks mainly lacustrine mudstones and oil shale at the base to deltaic sandstone at the top. The uppermost sandstone units interbedded with this mudstone bed of the Dongying Formation are another target for CO_2 storage. Based on reported data, the permeability of sandstone in the Dongying varies from 200 to 1000 mD, while the porosity is 20–32% (Yu, 2010; Lin et al., 2010; Pang et al., 2012; Yang et al., 2013). Core analyses from a single well from the Qikou sag to the south of Tanggu indicate that porosity and permeability range from 23 to 31% and 219 to 908 mD respectively in the Dongying Formation.

Water samples from the Dongying have reported salinities of around 3000 mg/L, and are of HCO_3-Cl-Na type (Meng, 2007). Water pH determined in situ indicates that the water is alkaline with an average pH of 8.29 (Meng, 2007). Downward from the top of the Dongying Formation, salinity and fluid pressure increase rapidly with depth, and the unit is significantly over-pressured (Fig. 2).

3. Reservoir performance

Secure carbon storage requires identification of suitable geological formations that will have the capacity to store large volumes of CO_2 while preventing its escape to the atmosphere. Suitable storage formations will have inter-connected voids (spaces between rock grains) to allow the injected CO_2 to permeate the formation. In addition, suitable storage formations will be covered with

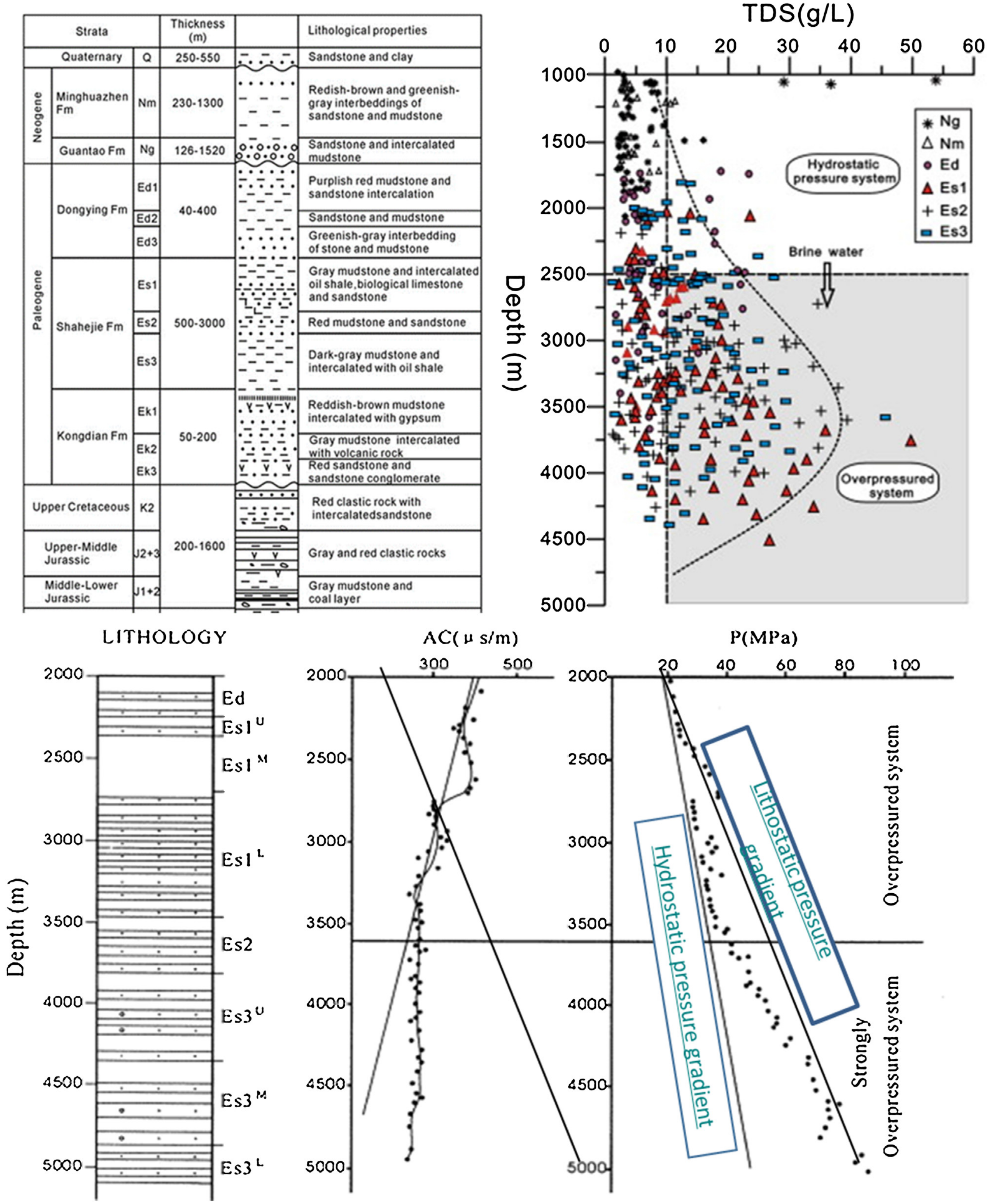

Fig. 2. Variation of total dissolved solid (TDS) with depth and pressure in the Neogene and Paleogene formations in the Qikou sag (upper right). As indicated by the departure from the hydrostatic gradient (straight line) pressure increases with salinity rapidly above the top of the Paleogene (lower right) Ng = Guantao Formation; Nm = Minghuazhen Formation; Ed = Dongying Formation; Es1, Es2, and Es3 are the first, second, and third member of the Shahejie Formation. Upper left figure from Yang et al. (2013). Remaining figures from Du et al. (2010). Note: AC = conductivity; P = pressure.

impermeable rock to permanently trap the injected, supercritical CO_2 underground. These rock formations are found at considerable depth-typically greater than 1000 m below the surface where their void spaces are often filled with saline water. In the following reservoir performance assessment, the cap-rock (Minghuazhen Formation) is assumed to be perfectly sealing and all uncertainty in the subsurface system is assigned to the permeable Dongying and Guantao formations.

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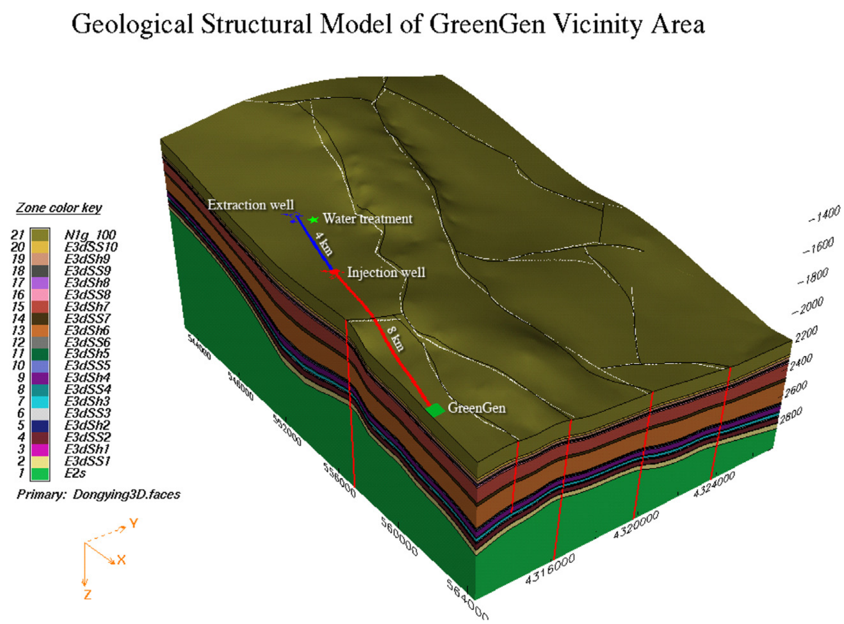

Fig. 3. Geologic model around the Bin Hai New Area and a hypothetical location of a CO_2 injection and water production well.

Using a geologic model of the area, a site was chosen to the west of GreenGen in a fault bounded block approximately 5 km × 15 km. Fig. 3 shows hypothetical injection and production well locations within this block. Here, we present initial estimates of CO_2 injectivity and plume radius for injection of 0.1 MT/yr and 1 MT/yr. Results for 1 and 10 years of injection are used to show how the plume from a single injector well could grow through time for a simplified, idealized system. Most results are for a 2 km deep injection well, while several results from a deeper plume are also presented to demonstrate the impact of changing depth and temperature.

3.1. CO_2-PENS radius and injectivity calculations

We use CO_2-PENS, a system analysis tool developed for the US National Risk Assessment Partnership (NRAP) program (Pawar et al., 2014). This tool has been built using the GoldSim© platform (GTG, 2010) allowing fast development of models that perform multi-realization, probabilistic simulations. A FORTRAN dynamic link library (DLL) coupled to GoldSim© is used to calculate plume radius using the following equations presented in Stauffer et al. (2009).

To calculate the CO_2 plume thickness, b, as a function of radius and time (r and t) we use the analytical expression given by Nordbotten et al. (2005):

$$b(r,t) = B\left(\frac{1}{\lambda_c - \lambda_w}\right)\left(\sqrt{\frac{\lambda_c \lambda_w V_t}{\phi \pi B r^2}} - \lambda_w\right) \quad (1)$$

where λ_c and λ_w are the CO_2 and water mobilities (the ratio of phase relative permeability to phase viscosity), B is the permeable reservoir thickness, and V_t is the total available volume of CO_2. Eq. (1) can be solved for the maximum plume radius, r, at a given time by setting the plume thickness, b, to zero as:

$$r = \sqrt{\frac{\lambda_c V_t}{\lambda_w \phi \pi B}} \quad (2)$$

Injectivity is calculated using a reduced order model (complex function) based on 1000 s of simulations of multiphase CO_2 injection into brine using a 2D radial mesh with varying permeable reservoir thickness, depth, temperature and excess pressure of injection (Middleton et al., 2012). The underlying simulations assume a single well with a fixed hydrostatic drain at a radius of 20 km, thus acting like a nearly infinite reservoir. A simple linear relative permeability function is used with relative permeability of CO_2 and water going from 0 to 1 as effective phase saturation goes from 0 to 1 (Stauffer et al., 2009). Capillary pressure also follows a linear model with maximum capillary pressure fixed to 1 MPa. Another simplifying assumption is that the water has zero salinity. Initial pressure is assumed hydrostatic in these calculations based on data shown in Fig. 2, where hydrostatic pressure extends from the surface to 2500 m depth. Finally, excess pore pressure (EPP) in the injection interval is calculated based on the specified flow rate.

Table 1
Well TR21 data for Productive Layers in the Dongying Formation. Note: Ed1-3 are subunits of the Dongying Fm. shown as Ed in Fig. 2.

Formation	Depth (m)	Thickness (m)	Porosity (%)	Permeability (mD)
Ed1	1950.1–1963.1	13	27.51	625.25
	1978–1984	6	26.64	480.03
	1989.4–1996.7	7.3	23.35	218.93
Ed2	2073.3–2090.1	16.8	31.41	908.16
	2202.2–2207.6	5.4	31.02	812.55
Ed3	2213.0–2220.0	7	29.98	725.69
	2249.7–2278.8	6.4	25.94	389.88
	2272.3–2278.8	6.5	26.04	406.29
	2284.3–2312.6	28.3	23.41	275.69
	2320.2–2324.9	4.7	26.41	421.98

3.2. Model parameter selection

Model parameters (permeability, porosity, and permeable thickness) are based on extensive data reported in the literature reviews offer two potential regional target reservoirs, the Dongying and Guantao formations (Table 1). Both have beds of high permeability and porosity intercalated with lower permeability layers of mudstone and shale (Yang et al., 2013). As described in the previous section, simplified relative permeability and capillary functions are embedded in the underlying reduced order model. Within CO_2-PENS, normal probability distributions that span the range of data in Table 1 were chosen for the primary parameters of permeability, porosity, and thickness. Due to limited data for the Guantao, it is

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assumed that permeable layers in this unit are similar in thickness to those found at Well TR21 in the Dongying. Two depths are explored in the simulations, 2000 m and 2500 m, representing intermediate and deep cases. Deeper plumes will have slightly smaller radius because radius is proportional to the square root of water viscosity divided by CO_2 viscosity times CO_2 density as (Stauffer et al., 2009):

$$r \propto \sqrt{\frac{u_w}{u_c \rho_c}} \tag{3}$$

The two depths that are simulated both lie well below the critical pressure and temperature for CO_2 (7.39 MPa and 31.10 °C) and all simulated CO_2 plumes remain as supercritical phase and do not experience phase change. The supercritical pressure corresponds to a depth of less than 800 m, meaning that CO_2 phase change does not become an issue until any leakage travels a minimum of 1.2 km upward from the injection horizons, and the phase change region is outside the scope of the current study.

Fig. 4 shows the CO_2-PENS reservoir input dashboard with parameter ranges used in the 2 km deep simulations and a subset of the dashboard for the deeper 2.5 km case. Ed1, Ed2, and Ed3 are the first, second, and third member of Dongying Formation. In this table, Ed1-3 are subunits of the Dongying Formation shown as Ed in Fig. 2. Fig. 5 shows the distributions of properties that were sampled for 100 Monte Carlo (MC) realizations in each simulation. Properties that were fixed for all simulations include residual water saturation (0.30) and injector well radius (0.07 m). Dissolution of CO_2 in brine and pore compressibility are not accounted for in these calculations. No consideration has been taken for pressure drops in the wellbore that could lead to borehole degradation. Further, the ROM was built from multiphase flow simulations where water is being withdrawn from the system along a constant pressure boundary located 20 km from the injectors.

3.3. Model results

Table 2 shows the average plume radius and excess pore pressure (EPP) at the wellbore required to achieve the target injection rate in a single well. After one year at the low injection rate of 0.1 MT/yr, the mean plume radius is only 0.39 km, showing that monitoring wells designed to detect CO_2 breakthrough in this time would need to be placed quite close to the injection well. When injection is increased to 1 MT/yr, the plume at one year averages 1.22 km. Average values give a good sense of differences between simulated cases. However, because of uncertainty in parameters for a given case, variability in plume radius changes by a significant amount for each of the 100 MC realizations of a given case. Fig. 6 shows how the plume radius varies with both layer thickness and porosity for the case of 2.5 km depth, 0.1 MT/yr, and 10 years of injection. The right side of Fig. 6 rotates the 3D view to show the strong inverse correlation between layer thickness and plume radius. As predicted by Eq. (3), average plume radius decreases (3.85 km–3.48 km) as depth increases (2 km–2.5 km) for the case of 1 MT/yr for 10 years. A similar decrease in radius is seen for the 0.1 MT/yr case.

Histograms for EPP and plume radius for the two cases are shown in Fig. 7. Clearly there are cases where injection of 1 MT/yr into one layer results in very high EPP (>4.0 MPa). High EPP is of concern due to the possibility of either hydrofracture or induced seismicity. A simple calculation of lithostatic stress relative to hydrostatic (using 25% porosity and a formation density of 2650 kg/m^3) yields Fig. 8A, where at 2.5 km depth a low estimate of hydrofracture (65% of lithostatic) is 10.6 MPa of EPP (Stauffer et al., 2009). However, overpressure is seen in some formations around Tianjin (Fig. 8B) and care will need to be taken to measure in-situ pressure conditions before setting injection rates as high as 1 MT/yr. In fact, Fig. 8B shows that at 3200 m depth, pressure is within only 2 MPa of the 1.6 pressure coefficient line (approximately 0.7 × lithostatic). For 0.1 MT/yr there is low probability of exceeding 0.65 × lithostatic, with most EPP values well below 0.5 MPa (Fig. 8C). Because of high permeabilities found at this site, a single well should be able to inject up to 1 MT/yr, especially if background pressure is near hydrostatic and the injection well is screened in a high permeability layer with thickness greater than 10 m.

Sensitivity analysis of the parameters shows that injection layer thickness has the most impact on plume radius variability (65%), while porosity and permeability provide much smaller contributions to uncertainty (7.5% and 4.3% respectively). Table 2 shows the average plume radius and excess pore pressure (EPP) at the wellbore required to achieve the target injection rate in a single well. Excess pore pressure is controlled by a combination of thickness and permeability (37.2% and 33.5% respectively), with porosity variation having little impact (1.2%). Fig. 9A shows the variability in injection EPP as a function of permeability and thickness for 100 realizations (1 MT/yr, 10 yrs, 2 km). The largest injection EPP of 8.24 MPa results from a combination of low thickness (5.6 m) and relatively low permeability (250 mD). Fig. 9B shows the strong negative correlation between injection EPP and thickness of the injection interval for the same case.

3.4. Discussion of reservoir performance

Reduced-order calculations of injectivity and plume radius support the viability of the Guantao and Dongying formations as CO_2 injection reservoirs. Low excess pore pressure is required to inject up to 1 MT/yr in many cases, implying that a single well will be required to inject CO_2 from the GreenGen facility. Plume radius for the initial injection at 0.1 MT/yr is likely to be quite small (0.39 km) after one year. If a project goal is to detect breakthrough within this time, a monitoring well will need to be placed close to the injection well. Water production could likely take place within 2 km from the injector and not encounter breakthrough at 0.1 MT/yr injected for 10 years. For 1 MT/yr, the one year average plume radius is on order of 1.2 km, suggesting that a monitoring well could be placed farther from the injector. The water production well for the 1 MT/yr case would likely need to be located approximately 6–8 km from the injection well to ensure limited breakthrough. These calculations are conservative because we do not include reservoir management strategies such as pre-injection water production to lower pressures, multiple sets of injection and production wells, or heterogeneity in the high permeability layers. More detailed analysis will only be possible when higher resolution site data become available, such as 3-D seismic density maps and pump tests on existing geothermal and/or new test wells.

4. Reservoir management

Injection of CO_2 into the subsurface creates high pressure regions around injection wells. Storage capacity is controlled by pressure buildup in the storage reservoir. A few project-specific variables dominate the degree to which pressure buildup occurs in a storage reservoir: (1) the volume and net rate of fluid injection (injection minus production) in the reservoir; (2) the accessible pore volume within the reservoir "compartment," determined by the geology and hydrogeologic properties of the reservoir rock (e.g., residual liquid saturation); and (3) the permeability of the reservoir and adjacent seals that define the compartment (Buscheck et al., 2016a). To ensure containment in the storage reservoir, formation

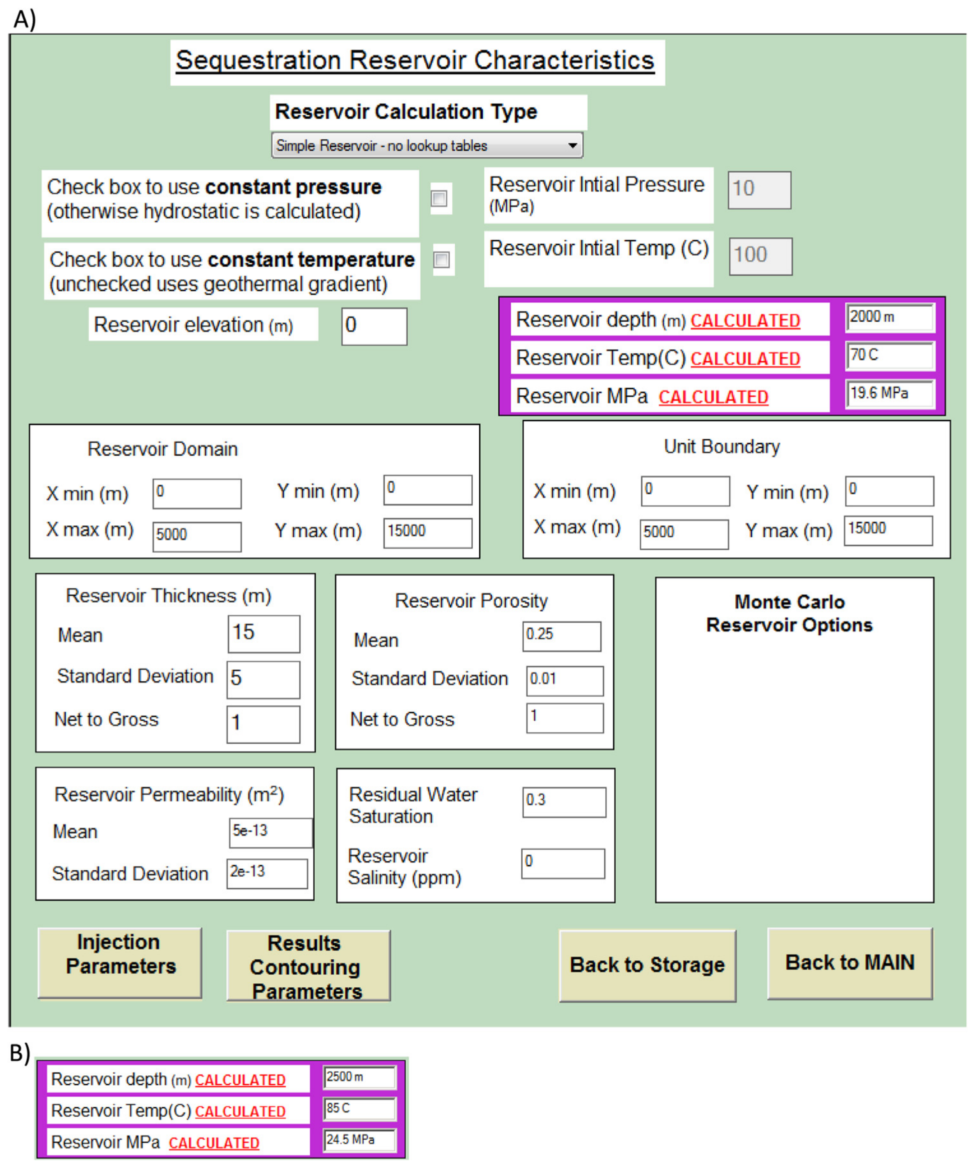

Fig. 4. (A) CO_2-PENS reservoir dashboard showing input parameters and calculated properties. Grey boxes are not used. (B) The only difference for the deeper 2.5 km cases is the initial pressure and temperature. Note: reservoir salinity assumed zero as a simplifying parameter.

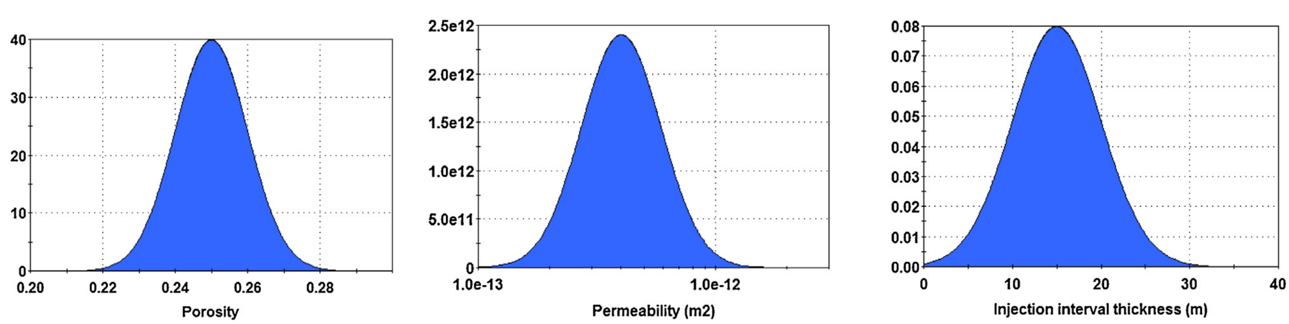

Fig. 5. Porosity, permeability, and thickness distributions within CO_2-PENS for target injection layers representing the Guantao and Dongying formations.

pressure should not exceed the yield strength of the sealing (cap) rock.

Some storage projects have encountered difficulties due to limitations on total storage capacity or injection rate imposed by insufficient reservoir pore volume or permeability. The Snøhvit CO_2 project is one such example (Hansen et al., 2013; Shi et al., 2013) where it was found that the desired injection rate into the initial target formation, the Tubåen, could not be sustained. Geologic surveys, geologic logs, and core data can be used to estimate the pore volume and permeability of a prospective reservoir. But estimates of storage capacity and permanence will have large uncertainties until operators have experience moving large quan-

Table 2
Plume Radius and Injectivity Results.

Depth (km)	Injection period (years)	Injection rate (MT/yr)	Mean radius (km)	Mean EPP (MPa)
2	1	0.1	0.39	0.24
2	1	1.0	1.22	1.94
2	10	0.1	1.22	0.25
2	10	1.0	3.85	2.03
2.5	10	0.1	1.10	0.22
2.5	10	1.0	3.48	1.73

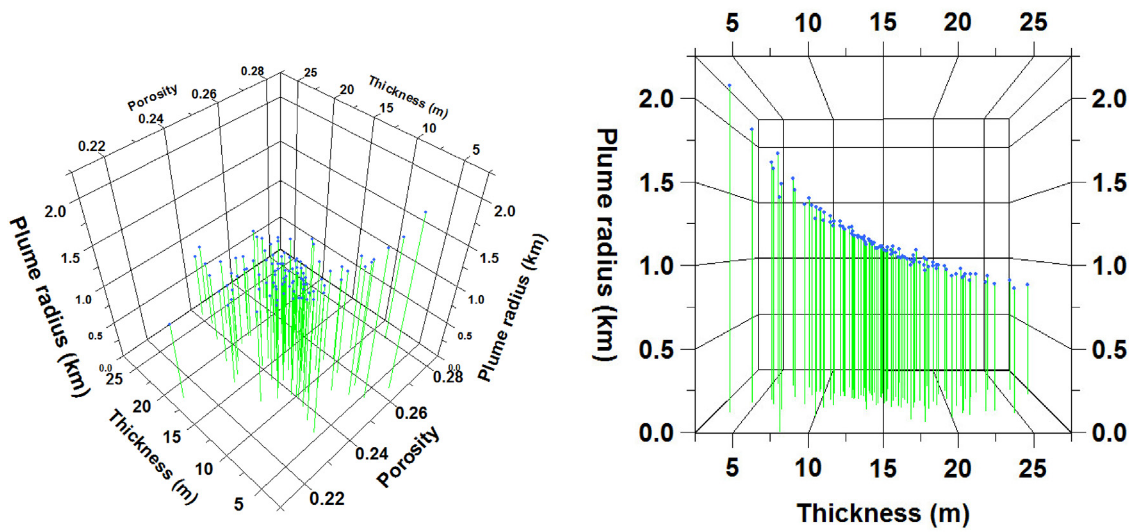

Fig. 6. Plume radius variation with thickness and porosity (0.1 MT/yr, 2.5 km deep, 10 year injection).

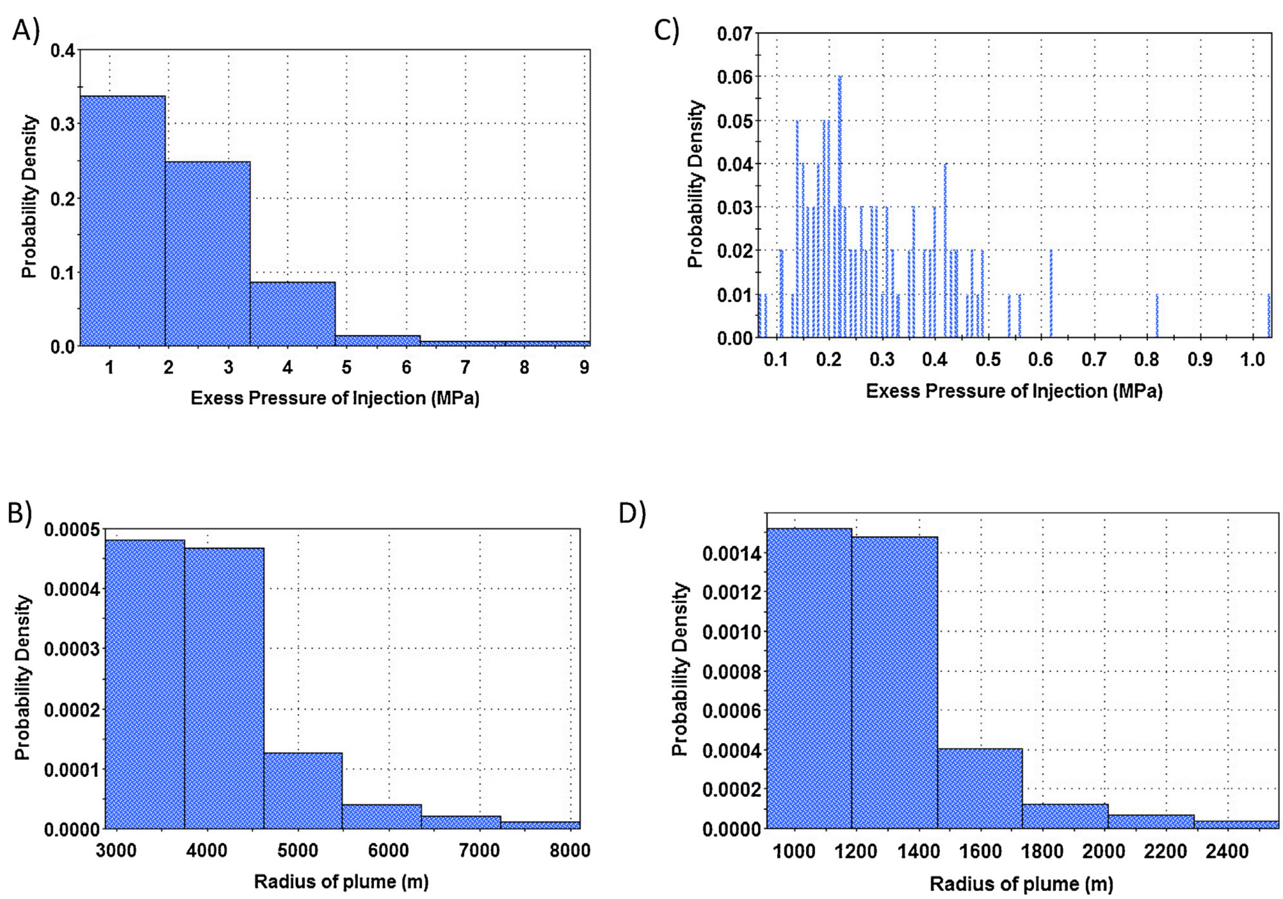

Fig. 7. EPP and plume radius histograms for (A,B) 1 MT/yr, 10 yrs, 2 km and (C,D) 0.1 MT/yr, 10yrs, 2 km. Probability density shows the relative probability of a given bin in the histogram.

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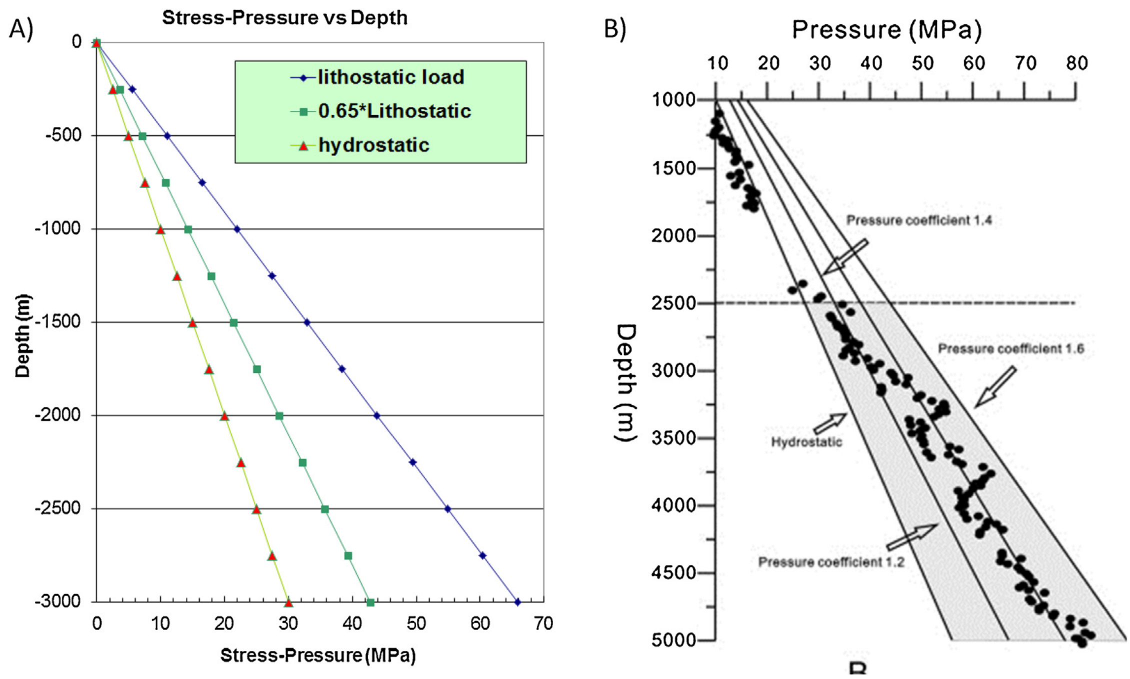

Fig. 8. (A) Lithostatic stress relative to hydrostatic and 65% of lithostatic failure line and (B) Pressure data from the Qikou Sag near the target injection site.

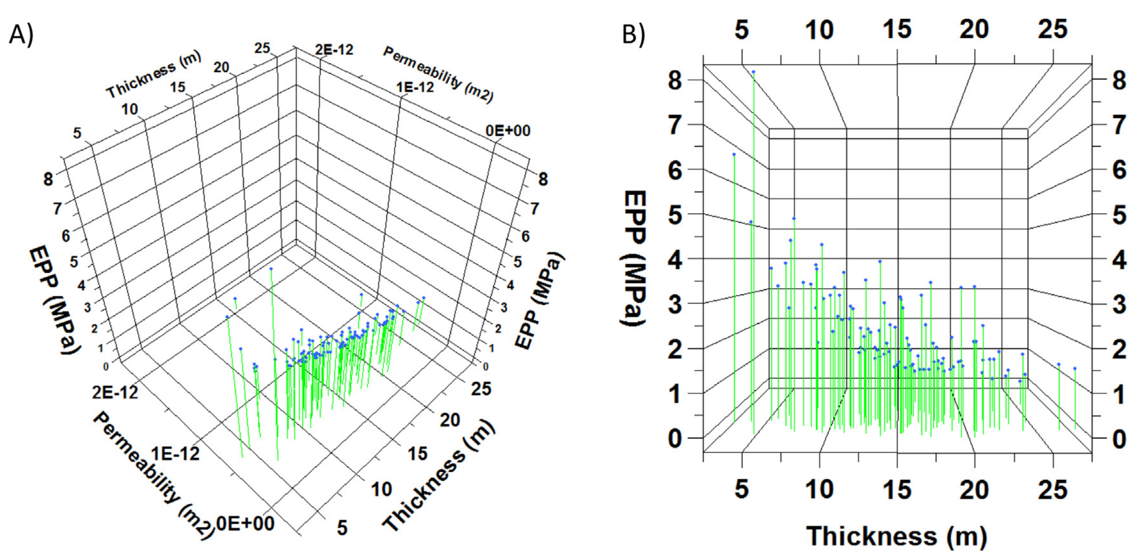

Fig. 9. Injection EPP variability versus thickness and permeability.

tities of fluid into and/or out of the storage reservoir (Buscheck et al., 2016a). Reducing this uncertainty could be necessary prior to securing financing of CO_2 storage infrastructure (U.S. National Coal Council, 2015). As discussed below, producing formation water in a prospective storage reservoir prior to CO_2 injection enables an assessment of storage capacity and whether that capacity is sufficient for commercial-scale CO_2 storage (Buscheck et al., 2016a).

There are two options for management of pressures within the target reservoir: passive and active. Under passive management, CO_2 displaces formation water and the resulting plume moves in response to uncontrolled pressure gradients in the reservoir rock. In active management, water is withdrawn (extracted or "produced") serving several purposes (Buscheck et al., 2014, 2016a,b).

There are two options for management of pressures within the target reservoir: passive and active. Under passive management, CO_2 displaces formation water and the resulting plume moves in response to uncontrolled pressure gradients in the reservoir rock. In active management, water is withdrawn serving several purposes (Buscheck et al., 2014, 2016a,b). Formation water removal opens pore space in the reservoir for CO_2 storage, resulting in less over-pressure, a smaller area of review (AoR), and less post-injection monitoring for a given quantity of stored CO_2 (Buscheck et al., 2012, 2016a). Pressure drawdown around water production wells also helps direct CO_2 migration (Buscheck et al., 2011). Thus, active reservoir management can control the CO_2 distribution throughout the reservoir.

4.1. *Pre-injection formation water production overview*

Reservoir pressure management using separate CO_2-injection wells and water-production wells has been considered in many CO_2 reservoir studies (Bergmo et al., 2011; Birkholzer et al., 2012;

Breunig et al., 2013; Buscheck et al., 2011, 2012; Court et al., 2012; Deng et al., 2012; Dempsey et al., 2014; Heath et al., 2013 Hermanrud et al., 2013; Roach et al., 2014). The trade-off between achieving early pressure relief and delayed CO_2 breakthrough has been identified as a key challenge. Early pressure relief requires close well spacing between the CO_2 injectors and water producers, but delayed CO_2 breakthrough requires large well spacing (Buscheck et al., 2012). The use of separate injectors and producers requires good hydraulic communication between those wells, which cannot be guaranteed. Some geologic formations are compartmentalized (Hansen et al., 2013; Shi et al., 2013), which limit hydraulic communication between wells and diminish the benefit of removing water to relieve pressure at CO_2 injectors. Early CO_2 breakthrough may require that the affected water producers be abandoned and additional water producers be installed elsewhere. Early CO_2 breakthrough and poor hydraulic communication between wells can increase capital and operating costs of reservoir management.

However, when active reservoir management is implemented using a pre-injection water-production strategy with the same well being used to produce water before injecting CO_2 (Buscheck et al., 2014, 2016a), each well can be used more efficiently because pressure drawdown is centered where pressure buildup due to CO_2 injection will occur. Further, because the resulting pressure drawdown jinversely correlates with pressure buildup from CO_2 injection, it generates data that can be used to (1) estimate CO_2 storage capacity, (2) determine whether a prospective site has sufficient capacity for commercial-scale CCS, and (3) plan well-field operations before any CO_2 is injected (Buscheck et al., 2016a). Reducing storage uncertainty and providing information for proactive reservoir-management planning can reduce project cost and risk.

4.2. Pre-injection water production strategy for this study

We propose deploying an approach for geologic CO_2 storage that combines CO_2 injection with water production where each deep well completed in the storage formation (Fig. 10) is sequentially used for three purposes: (1) monitoring, (2) removal of formation water and (3) CO_2 injection. Wells will be in place to monitor the subsurface during pre-injection water production so key data is acquired and analyzed prior to CO_2 injection. These data can be used to better define location specific reservoir properties and to help guide reservoir operators in making follow-on well placement and flow-rate decisions. This pre-injection information can help achieve optimum subsurface CO_2 storage utilization, which will reduce project cost and risk. The produced formation water will be desalinated and treated for use in industrial applications including cooling tower makeup water and high purity water for steam.

Pre-injection water production addresses key needs for effective CO_2 storage. The first need is to cost-effectively acquire data necessary to inform reservoir management decisions in a timely manner. Establishing that a site is potentially suitable for CO_2 storage—including minimizing the risk of CO_2 leakage—requires that sufficient data and information be acquired and analyzed prior to CO_2 injection. Site suitability requires identifying a caprock with sufficient seal integrity for containing the buoyant, pressurized CO_2 plume. A sufficiently tight caprock seal is also necessary to efficiently reduce pore pressure by producing water. Site suitability also requires that the target CO_2 storage zone(s) have sufficient compartment volume(s) for the intended CO_2 storage capacity without incurring too much overpressure. CO_2 storage capacity may be greatly increased with a reservoir pressure management strategy that removes water from the CO_2 storage compartment. Such a strategy may also mitigate various operational and environmental risks.

Our proposed approach (Buscheck et al., 2014, 2016a,b) requires a shallow monitoring well and a minimum of two deep wells completed in the candidate CO_2 storage target zones (Fig. 10). Initially, this will involve producing water from several candidate CO_2 storage target zones, while monitoring the pressure response in an adjoining deep monitoring well and in a shallow monitoring well (Fig. 10). The goal is to identify a CO_2 storage target zone that is overlain with a caprock seal that is sufficiently tight to constrain the upward migration of buoyant CO_2 and to prevent the downward migration of water during the pre-injection water-production stage (Fig. 10). Preventing this downward water migration is important because any downward flux of water into the target CO_2 storage zone would partially defeat the purpose of water production—to reduce pore pressure, and thus accommodate more CO_2 injection without incurring too much pore overpressure. Once a suitable CO_2 storage target zone is identified, additional water production can continue in that zone until the pressure perturbation is sufficient to inform reservoir managers about the hydrologic properties of the CO_2 storage reservoir. Together with the pressure response at the shallow monitoring well, this extended pressure drawdown test (Fig. 11) can be used to estimate the effective compartment volume of the target CO_2 storage zone and the contribution of caprock leakage on pressure relief.

During the pre-injection water-production stage, an ensemble of tracer slugs can be released along the second deep well (the deep monitoring well in Fig. 10a). Tracking the arrival times of the respective tracer slugs at the water-production well can help forecast the CO_2 breakthrough time that will occur during the CO_2 injection stage. Together with pressure measurements (Fig. 10) this information can help reservoir managers plan the timing and rates of CO_2 injection and water production that will be implemented during the CO_2 injection stage (Fig. 10b).

Monitoring pressure and the migration of the CO_2 plume during the CO_2 injection stage will provide useful information that may be used to locate a potential third deep well that could be used for water production (if the decision is made to extend CO_2 storage operations). This process would involve moving CO_2 injection from the first to the second deep well (Fig. 10c).

4.3. Pre-injection water production discussion

A key advantage of our proposed approach is that CO_2 is injected at the location of maximum pressure drawdown due to the pre-injection water production. Thus, it will take some time before pore pressures in the vicinity of the CO_2 injector reach initial formation pressure during the CO_2 injection stage. Consequently, pre-injection pressure drawdown buys time and allows reservoir operators to locate the next water producer further away from the CO_2 injector than would be possible if separate injectors and producers had been used. Increased well spacing will delay CO_2 breakthrough and extend the operating lifetime of water producers (Buscheck et al., 2016b).

The efficacy of using the same well to produce water prior to injecting CO_2 was tested with a calibrated model of CO_2 injection at Snøhvit (Buscheck et al., 2016a). On a volume-per-volume basis, formation water removal was found to be 94.4% effective—i.e., for each cubic meter of water removed from the reservoir, an additional 0.944 cubic meters of CO_2 could have been injected while maintaining the same peak reservoir pressure. While the size of reservoir compartment in the Tubåen Fm. at Snøhvit was small (0.51 km^2), a recent study (Buscheck et al., 2016b) analyzed the effectiveness of pre-injection water production for a larger reservoir compartment (20 km^2). For the cases considered, the volume-per-volume water-removal effectiveness ranged from 77 to 100%, with the lowest value pertaining to a case where 100% of the produced water was reinjected in a reservoir immediately

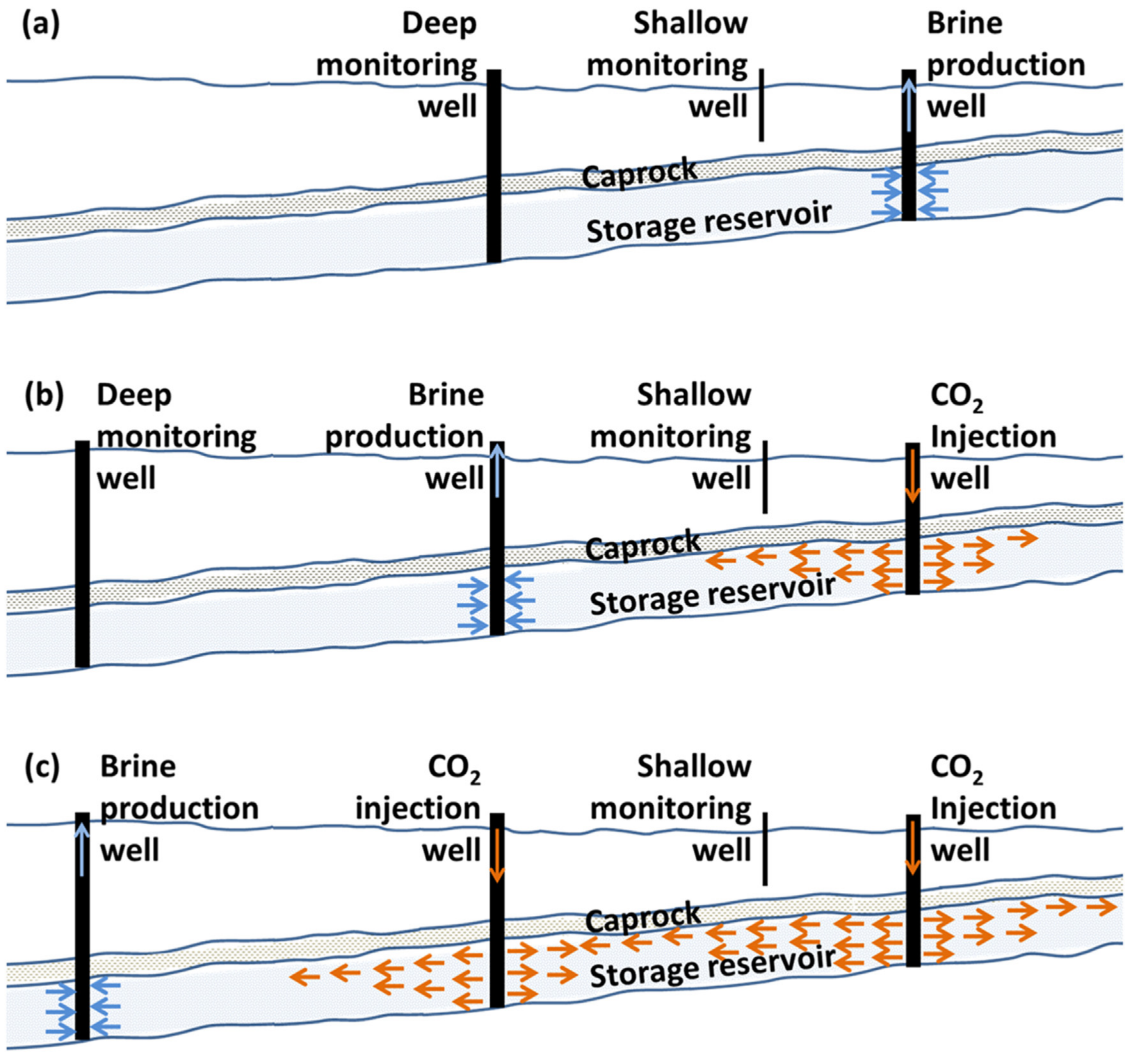

Fig. 10. Staged pre-injection formation water (brine) production is shown for multiple wells (Buscheck et al., 2014). (a) Pre-injection brine production results in pressure drawdown, making room for CO_2 storage. (b) The brine-production well in (a) is repurposed for CO_2 injection and the deep monitoring well is repurposed for brine production. (c) The brine-production well in (b) is repurposed for CO_2 injection and brine production is moved to a third deep well, which could continue after CO_2 injection is ceased.

above the CO_2 storage reservoir. Results from these recent studies (Buscheck et al., 2016a,b) indicate pre-injection water production is likely to reduce the total number of wells required to execute reservoir pressure management, compared to the use of separate injectors and producers, which should reduce capital cost. Because our approach requires less water production to achieve a targeted level of pressure relief than would be required with separate injectors and producers, our approach should also reduce operating cost.

While pre-injection water production can be useful in addressing the risks of pore overpressure, there may be limitations, based on geomechanical constraints, by how much, or how fast, pressure can be drawn down in a storage reservoir. So, executing this approach will require careful consideration of geomechanical interactions. In summary, our proposed approach is designed to provide timely, cost-effective information and pressure reduction where it is most needed: at the center of the CO_2 storage zone. Moreover, our approach is proactive in that it can help identify the target CO_2 storage zone (or zones) that will be most suitable for CO_2 injection, prior to that injection. This understanding reduces environmental and financial risk. Our approach can achieve reservoir pressure management with fewer wells and with less water removal than an approach that uses separate injectors and producers, which will reduce capital and operating costs. Our approach also generates product water earlier, which accelerates the utilization benefits.

5. Produced water treatment

Production of water during, or prior to, CO_2 carbon storage operations provides a mechanism for reducing the risks associated with CO_2 storage, by controlling CO_2 movement and providing pressure control. At the same time, formation water production provides a water resource for human use. Understanding the goals for water use at the surface will dictate the treatment processes, treatment train design, and costs for creating a useable water stream. Likewise, understanding the physics and mechanisms of CO_2 storage, and the expected physical outcomes of storage processes, will impact capital investment and infrastructure decisions for water treatment. During a preliminary system design phase, site-specific information may not be available and so literature data must be used to assess treatment train processes and costs. Our goal with this analysis is to provide and evaluate reasonable cost ranges for appropriate treatment levels, but not to provide specific treatment methods or costs given the uncertainties in initial water quality, site parameters, and final system design considerations that will be determined in the future. We have shown that early cost ranges

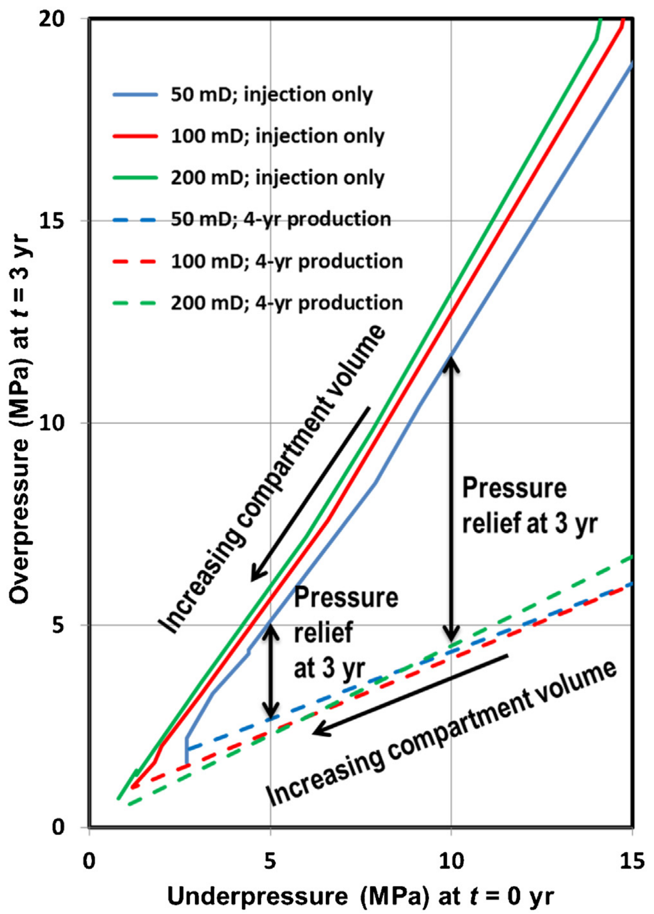

Fig. 11. Overpressure three years into CO_2 injection stage is plotted as a function of underpressure after 4 years of pre-injection brine production (dashed lines). Also plotted is overpressure for the corresponding cases with no brine production (solid lines). Reservoir permeability values of 50, 100, and 200 mD are considered. Caprock permeability is 0.001 mD. A wide range of reservoir compartment area (1–300 km^2) and thickness (100–300 m) are considered. CO_2 injection rate and brine production rate is 1 million ton/year. Because the magnitudes of injection and production rates are relative to the compartment storage volume, this plot is representative of other injection and production rates; thus, it applies to commercial-scale CCS. The one-to-one correspondence between underpressure and overpressure directly informs reservoir operators about the CO_2 storage capacity as a function of brine production rate, including the case of no brine production (Buscheck et al., 2014).

estimates are appropriate to evaluate future cost risks, and system design risks, that may be encountered when combining CCUS and water treatment systems (Sullivan Graham et al., 2015).

Note that all cost values shown are in 2013 US$. All model values and results are for cubic meters (m^3) of water unless otherwise stated. In this study, modeling assumptions are based on U.S. infrastructure, water management, and regulatory systems, and as such, are useful for comparisons between modeled scenarios; international regulatory and management frameworks will be incorporated into the modeling during later phases of this research. This is a “one-way” analysis, in that the reciprocal effects of time-related reservoir responses to CO_2 injection and pressure-front variations, as well as changes in water chemistry over time, are not considered to have an effect on water production and treatment systems.

5.1. CO_2-PENS water treatment model (CO_2-PENS WTM)

The water treatment system must be linked to the CO_2 storage system operations to correctly evaluate the effects of different volumes, pressures, temperatures, and produced water quality on treatment train process choices and costs. The WTM was developed to provide estimates of treatment and related process costs (AACEI equivalent level 5, concept screening, or level 4, study or feasibility (AACEI, 2011)), and the complex relationships between processes when extracted waters are evaluated for use during CCUS and EOR site development. Costs are derived from literature values for individual processes. A detailed description of the model formulations, references used for cost basis, and model processes are giving in Sullivan Graham et al. (2014); the model is further described and validated against an engineering-type model in Sullivan Graham et al. (2015). The WTM was developed using the GoldSim© platform(2010). GoldSim© is used to develop analysis models that perform multi-realization, probabilistic simulations. A FORTRAN code captures the logic of treatment process selection and is linked within GoldSim©. GoldSim© utilizes custom data elements for input of user-specified parameters including stochastic distributions. The WTM captures all decision points; both stochastic range and constant data input values. Fig. 12 shows a model schematic diagram including the various sub-modules that calculate final costs and volumes. Output flow volumes from the reservoir simulation become the input flows (Q_{in}) for treatment in the WTM. Treatment steps, including organic and inorganic constituent pretreatments, membrane desalination (reverse osmosis or nanofiltration), thermal desalination (multiple-effect distillation, multistage flash distillation) are selected by the model based primarily on salinity ranges (TDS in mg/L) and the desired product water quality in mg/L; location data drives selection of transportation costs; volume data drives selection of storage costs and transportation modes. Brine concentrate disposal methods are based on US scenarios including evaporation ponds, deep well injection scenarios, or disposal to ocean or sewer systems.

We note that the CO_2-PENS WTM was developed using data, costs, and logic associated with systems found in the United States. This is particularly important for understanding the results for different disposal scenarios. Disposal of saline concentrate (residual brine) from water treatment is regulated under various discharge permits. Deep well injection, for example, is regulated by the U.S. Environmental Protection Agency Underground Injection Control Program (U.S. EPA, 2016). The type of well choice is influenced by the classification of the water source. For the WTM, a key difference is the distinction between oil and gas “produced” water, versus “non-produced” wastewaters from other sources. Produced water may only be disposed via a Class II injection well in the U.S., whereas other wastewaters may be disposed via Class I or Class V wells depending upon the source and potential risk to the environment. The WTM model makes this choice for the user once the user inputs the type of water to be treated (produced or not produced). It is anticipated that future uses of the model may incorporate scenarios and logic for different countries and regulatory perspectives.

Model parameters and water chemistry data were derived from literature reviews of two potential regional target reservoirs, the Dongying and the Neogene Guantao formation (Ng) (Pang et al., 2012; Yang et al., 2013). Both formations have relatively low salinities (<10,000 mg/L TDS) and low concentrations of scale-forming minerals including carbonates and sulfates and, thus, are good candidates for relatively economical water treatment. Ultimately the Guantao was chosen for the primary simulations, although several scenarios including salinity and temperature ranges for the Dongying were run to illustrate the effect of higher salinity on the model results (reported in Sullivan Graham et al., 2014). Scenario choices are shown in Table 3. The approximate volume expected from an initial pilot test of the system is 400 m^3/day. This volume is low compared to volumes treated by most water treatment plants; typical plants are often built to handle over 37,850 m^3/d.

The calculations and results include uncertainty in some parameters to show possible variations in costs. Electricity costs are

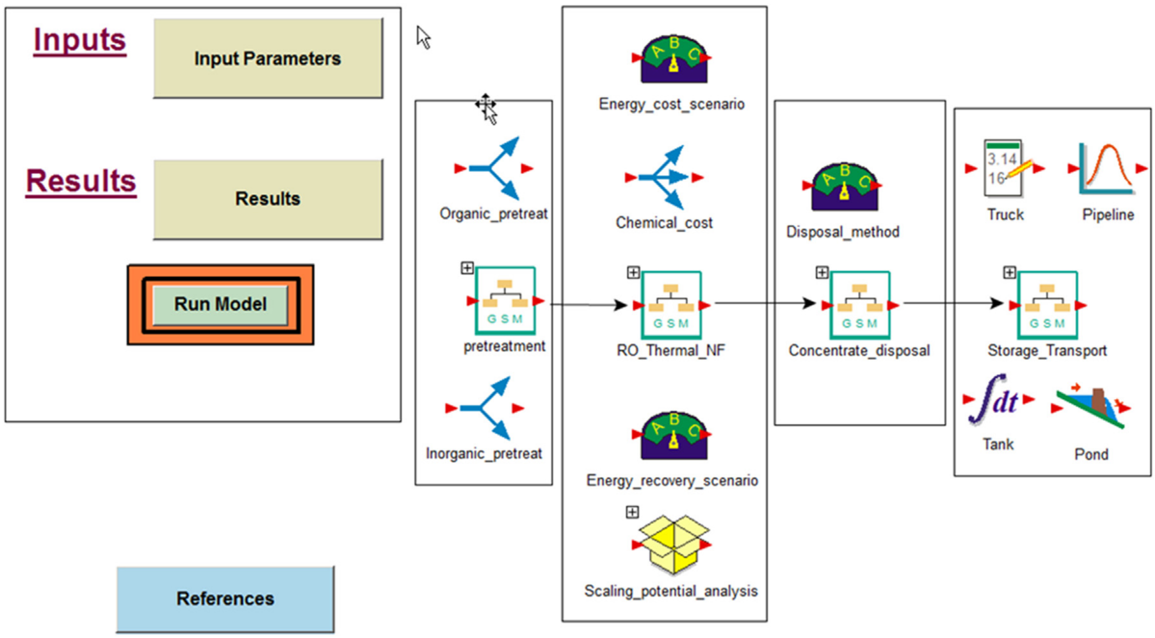

Fig. 12. CO_2-PENS WTM Schematic.

Table 3
Scenario Choices for Preliminary Cost Assessment.

Formation	Salinity Range (mg/L TDS)	Temperature Range (°C)	Produced Water Yes/No	Scenario ID-Product water quality
Guantao	716–1760	40–73	Yes	Case 7a-Boiler Water
Guantao	716–1760	40–73	no	Case 8a-Boiler Water
Guantao	716–1760	40–73	Yes	Case 7b-Cooling Water
Guantao	716–1760	40–73	no	Case 8b-Cooling Water
Guantao	716–1760	40–73	no	Case 8c-Cooling Water with organic pretreatment
Dongying[a]	1300–16,000	10–85	Yes	Case 1a-Boiler Water
Dongying[a]	1300–16,000	10–85	no	Case 2a-Boiler Water
Dongying[a]	1300–16,000	10–85	Yes	Case 1b-Cooling Water
Dongying[a]	1300–16,000	10–85	no	Case 2b-Cooling Water
Dongying[a]	1300–16,000	10–85	no	Case 2c-Cooling Water with organic pretreatment

[a] Results reported in Sullivan Graham et al. (2014).

assumed to be \$0.07/kW h (Lam, 2004; NEA, 2016). These calculations do not include costs related to borehole construction or compression of CO_2. For the Guantao Formation, CO_2 transport costs by truck for 400 m^3/day (i.e. ~0.15 MT/yr) from GreenGen to the injection site is included. Increased degradation of reverse-osmosis (RO) membranes can occur at the higher temperatures evaluated (>45 °C), and so treatment in this range may incur greater membrane replacement (O&M) costs than are calculated here. Model features and inputs include the cost of electric power (input); pre- and post-treatment methods, energy recovery options for membrane treatments; concentrate (residual brine) disposal options, transportation, and storage options (Sullivan Graham et al., 2014, 2015).

5.2. Model results-costs and sensitivity analysis

Multiple scenarios were run to determine the most representative cases for this study. Table 4 shows the average cost and standard deviation for selected treatment and disposal method for Guantao Fm. cases (8a–c), calculated using model output mean costs averaged over the total number of Monte Carlo realizations, divided by the amount of incoming water to be treated (Q_{in}). Figs. 13–15 show the plotted results. Each case was run with 500 model realizations. The model selects which treatment method is appropriate for each realization. The costs include water treatment,

Table 4
Guantao Results for Non-produced Water Cases.

Case (categorized by concentrate disposal method)	Average cost (US\$/m^3 incoming water)	Standard Deviation
8a-reuse	2.37	1.02
8a-surface discharge	3.12	1.47
8a-sewer	3.18	1.46
8a-ocean	2.55	0.26
8a-class V well	2.56	0.27
8a-zero-liquid discharge	2.59	0.28
8b-reuse	2.33	0.70
8b-surface discharge	2.92	1.21
8b-sewer	2.96	1.22
8b-ocean	2.27	0.54
8b-class V well	2.28	0.54
8b-zero-liquid discharge	2.30	0.56
8c-reuse	3.87	1.85
8c-surface discharge	4.45	2.23
8c-sewer	4.50	2.25
8c-ocean	3.85	1.69
8c-class V well	3.86	1.70
8c-zero-liquid discharge	3.88	1.71

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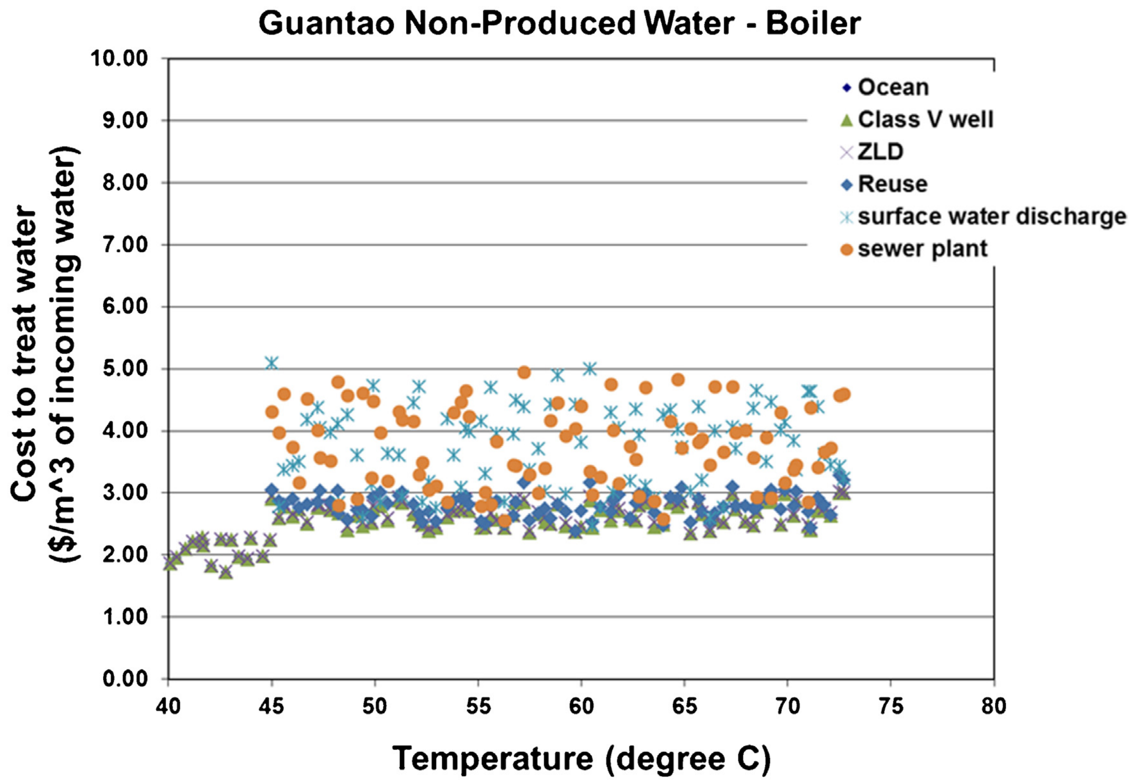

Fig. 13. Case 8a, Guantao Fm., non-produced water scenario for Boiler water treatment goal.

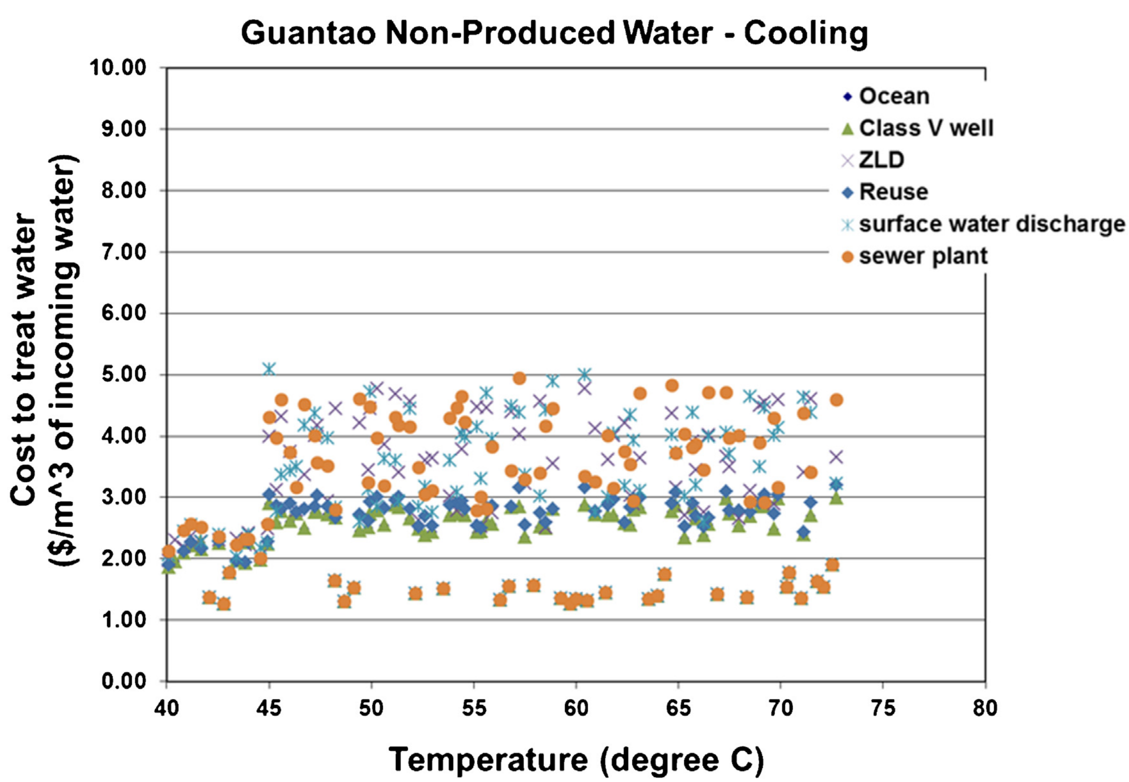

Fig. 14. Case 8b, Guantao Fm., non-produced water scenario for a cooling water treatment goal.

including membrane (RO) and thermal methods, concentrate disposal, transportation and storage. Costs calculated for scenarios where the produced brine temperature is 45 °C or greater represent mostly thermal primary treatments. Overall, 15% of the realizations use RO treatment, while 85% use thermal treatment. All of the Guantao scenarios have a number of potential disposal options, because the rejected concentrate is within reasonable salinity ranges (<3000 mg/L). We note that concentrate reinjection

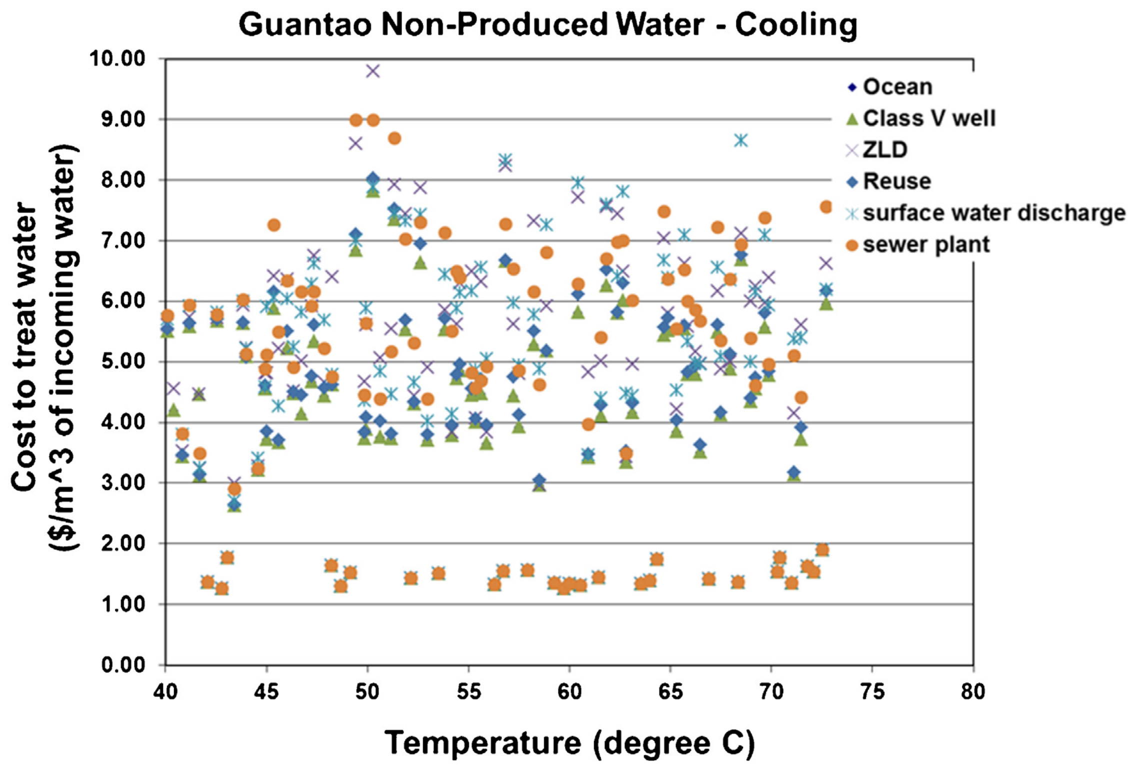

Fig. 15. Case 8c, Guantao Fm., non-produced water scenario for a cooling water treatment goal with organic pretreatment included.

could be used as an additional control to prevent subsidence under the correct conditions and reinjection depths. For this region, however, the most inexpensive options for concentrate disposal include discharge to the ocean or to a sewer. Cases 8b and 8c were chosen as sensitivity analysis demonstration cases, with and without organic pretreatment. In Fig. 14 (case 8b), model realizations incorporate a cooling water treatment goal of 1000 mg/L. The model selected RO treatment for 12% of the realizations, thermal treatment for 61% of the realizations, and the remaining realizations (27%) did not require treatment, indicating very low costs for this case.

In Fig. 15, the cost range is wider because of the addition of organic pretreatment. In this analysis, a stochastic distribution of costs was used to incorporate the wide range of potential treatment options that might be needed (Sullivan Graham et al., 2015). Organic pretreatment would be most important if the produced waters contain organic constituents that would damage RO membranes or would create regulated air emissions during water handling.

The WTM includes costs for Class II well disposal in the produced water scenarios (Sullivan Graham et al., 2014). These disposal costs are documented in the literature to range from \$0.06 to \$63.00 per m^3 of water disposed, contributing three orders of magnitude variation to these costs (Sullivan Graham et al., 2014). This result is based upon U.S. disposal cost ranges and thus may not be applicable to other locations outside of the U.S. The results show the effect that high disposal costs can have on the cost distribution.

A sensitivity analysis for the cooling scenarios 8b and 8c was conducted to show the relative importance of the input parameters on final costs. The importance measure is a normalized version of a measure discussed in Saltelli and Tarantola (2002). For scenario 8b (Fig. 16), water supply quality (TDS), truck transportation rates, and tank storage rates are indicated as being most important to costs, followed by parameters related to pretreatment such as antiscalant costs and feed pH. Transportation distances also have some significance, as well.

For scenario 8c (Fig. 17), the case with organic pretreatment included, we see a similar distribution of relative importance factors. Supply quality TDS is still the most important cost factor, followed by truck transportation rate, and organic pretreatment. Here the large cost variance of the latter increases its relative importance to other treatment factors (x axis), as expected.

5.3. Discussion of produced formation water treatment

The low influent volume ($Q_{in} = 400\ m^3/d$) for this test case may result in greater estimated costs per treated volume than for a full-scale treatment operation because economies of scale cannot be effectively included for transportation, storage, and other processes. However, the costs evaluated are relatively low compared to other site evaluations, because the treated waters are low in salinity (Sullivan Graham et al., 2014). In comparison, seawater treatment costs are approximately \$1–2 per metric ton ($1\ m^3$) of product water (NRC, 2008). This makes treatment a feasible option for this location (Sullivan et al., 2013). Short distances for transportation of water from the production point to the point of treatment, inexpensive and short distances for concentrate disposal transport, and the likelihood that the treated water would be used in near proximity to the treatment plant are also factors that make this scenario feasible. This model shows stochastic best estimates of cost ranges for early-stage estimations. More and better field data for a specific site will allow for more accurate cost evaluations for later stages of planning and for risk evaluation tradeoff analysis.

Expected recoveries from various treatments are listed in Table 5. Recoveries are quite good because the influent water quality is of relatively low salinity.

Organic pretreatment was evaluated for one of the Guantao Fm. scenarios, to indicate the effect that this step has on overall costs. While the Guantao Fm. is not identified as an oil and gas producing formation, it is used as an illustrative case given that many formations contain oil and gas reserves. If residual organic carbon is

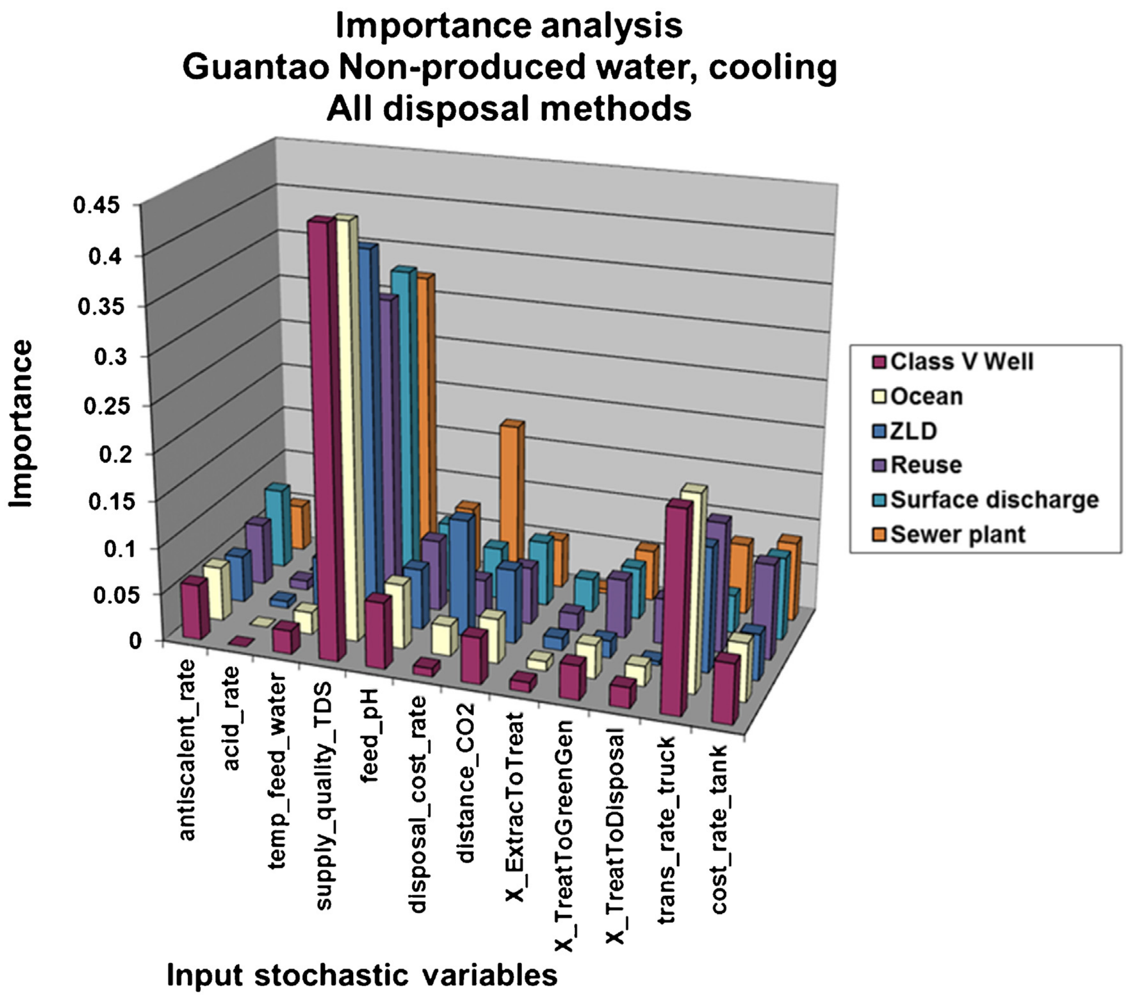

Fig. 16. Case 8b, importance analysis for cooling treatment goal stochastic parameters.

Table 5
Recovery Rate.

Case	Mean (%)	Standard Deviation
8a (produced water, boiler)	92.78	2.75
8b (non-produced water, cooling)	95.25	4.66
8c (non-produced water, cooling, organic pretreatment)	95.25	4.66

Note: standard deviation distribution confidence bounds represent the 5% and 95% confidence limits.

found in the produced water, then organic pretreatment may need to be considered, particularly for membrane treatment methods, or if volatile emissions from the treatment process are a concern (e.g., benzene, toluene, ethylbenzene, xylenes). Fig. 15 indicates that costs could increase by as much as \$2.00–\$4.00/m^3 if organic pretreatment is needed.

There are multiple pathways for concentrate (reject) disposal or use, as shown in the different model scenarios. While the model results are based upon discharge limitations for the U.S. and injection well criteria from the U.S. EPA, the model may need to be modified to include specific discharge or injection rules and costs for international use. The Guantao Fm. chemistry data indicate a low level of influent salinity, and, thus, concentrate reject will also not be very high in salinity and likely can be directly discharged to surface water, sewer, or the ocean. This is the most economical method of concentrate disposal and will keep treatment costs very low as long as expensive transportation methods are not needed.

Some concentrate disposal methods have very large standard deviations in reported costs. The reported capital and O&M costs are amortized over 25 years with 6% interest, and divided by a per-year volume for the plant to determine the cost/m^3 for each method; if no capital and O&M costs are reported the cost/volume reported data are used as they are. For example, zero-liquid discharge (ZLD) literature costs range from \$0.04/m^3 to \$20.00/m^3, with a median cost of \$5.84/m^3 and a standard deviation of \$6.35/m^3 (DiNatale et al., 2010; Kim, 2011; NRC, 2008; Boysen et al., 2003). A normal distribution is used to apply stochastic ZLD disposal costs. For this scenario, ZLD is an unlikely disposal pathway, because of the low salinity expected for the concentrate.

The cost for transport CO_2 to injection site is calculated in Dongying Formation non-oil bearing water scenario, the average cost is \$0.612/m^3. The CO_2 density under the compressed liquid condition (−30 °C at 1.7 MPa) is 1076 kg/m^3, which is very close to the water density (Stauffer et al., 2009). Therefore it is reasonable in this calculation assuming the CO_2 volume transported is the same as volume of water to be treated.

Potential uses for treated waters include industrial uses, such as the boiler water and cooling water treatment goals shown in this report, municipal, or agricultural use. Some limiting factors for these uses include a boron concentration of 5 mg/L (15 mg/L as borate ion). Boron is difficult to remove even with membrane processes; thermal processes may be more effective to reduce this below lower agricultural tolerance levels (1–15 mg/L; USDA, 2016).

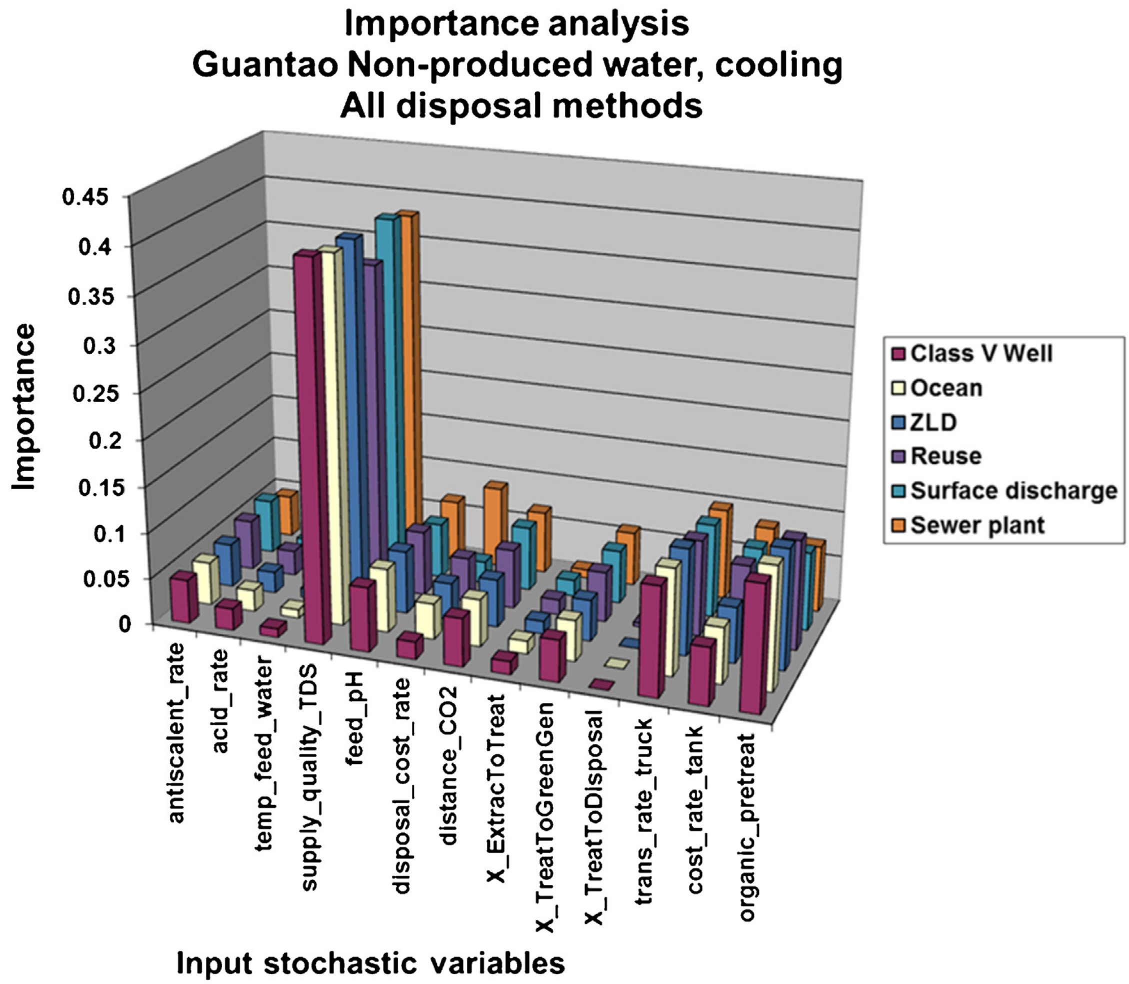

Fig. 17. Case 8c, importance analysis for cooling treatment goal stochastic parameters with organic pretreatment.

Further work will need to be done to better understand the site configuration, transportation distances, and disposal options and costs for a site-scale evaluation. It is critical to understand the water quality at the site over time; interconnections between formations or poor well completions may cause variations in chemistry and may indicate that shallow fresh water aquifers are being impacted by withdrawals.

6. Interactions between water treatment and reservoir management

In active reservoir management, there will need to be an ongoing dialog between the injection processes ("front end") and water treatment processes ("back end"). Over time, on the front end, changes will occur in injection locations, volumes of CO_2 injected, and horizontal and vertical locations of CO_2 saturation and pressure fronts, as shown in Fig. 10. On the back end, we can expect that subsequent changes will be needed in water production well locations and depths, inclusion of additional wells or shutting in of older wells, changes in locations or depths of waste disposal wells, and concurrent changes in the distance over which water and wastewaters will need to be transported, or depths from/to which waters and wastewaters will need to be pumped. Changes in water quality also may be expected over time. This is especially true if EWR is operated in a manner similar to EOR, where some breakthrough of CO_2 is allowed for system optimization. CO_2 breakthrough in the treatment water would likely necessitate a treatment step to remove the CO_2. CO_2 in the produced water stream would lower pH and result in increased metal solubility. All of these factors will have a strong influence on the costs incurred for treatment and possibly the feasibility of treatment, particularly if water quality changes occur.

An examination of the importance analysis shows the most likely processes wherein the treatment system will need to accommodate cost changes. Factors with high variance in the importance analysis are susceptible to (mostly) larger changes. For example, Fig. 17 shows that high importance lies in factors related to water quality, including TDS, pretreatment, and pH. High importance also lies in transportation factors. Less importance can be placed on waste disposal for the Tianjin site, because concentrate waste will likely be disposed via more accessible, less costly surface or ocean disposal options. Over time if TDS increases because of front end processes, costs will increase for the total system.

7. Conclusions

The project studied the GreenGen site in Tianjin, China where Huaneng Corporation is capturing CO_2 at a coal fired IGCC power plant. Known as the Tianjin Enhanced Water Recovery (EWR) project, the rock units in the vicinity of the plant were evaluated for CO_2 storage potential. We evaluated the potential for improving the efficiency of CO_2 storage by producing formation water to create additional storage capacity for CO_2 while simultaneously treating the produced water for beneficial use. Known as active reservoir

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management, we evaluated the feasibility of using this approach to control pressures within the target formation, lessen the risk of caprock failure, and better control the movement of CO_2 within that formation. We found that water production prior to CO_2 injection could efficiently manage reservoir pressure and, because the resulting pressure drawdown inversely correlates with pressure buildup from CO_2 injection, it can be used to estimate CO_2 storage capacity and plan well-field operations. A novel dual purpose well strategy was identified wherein the same well would be used for, first, water production, then, CO_2 injection. This would result in significantly less infrastructural investment while better characterizing formation storage properties in the exact location of CO_2 injection.

Treatment goals were developed for the produced water. Average treatment cost for water with a cooling water treatment goal ranged from 2.27 to 2.96 US$/m^3 (recovery 95.25%), and for a boiler water treatment goal ranged from 2.37 to 3.18 US$/m^3 (recovery 92.78%). Importance analysis points to water quality and surface transportation parameters as the most important contributors to cost variance. From the viewpoint of a longer-term treatment system installation, these factors are also likely to be the most important to evaluate reciprocally for treatment system cost increases as CO_2 plume migration and evolving injection infrastructure changes occur. The study found that in a broad sense, active reservoir management in the context of CCUS/EWR is technically feasible. In addition, we propose criteria for evaluating suitable vs. unsuitable reservoir properties, reservoir storage (caprock) integrity, a recommended injection/withdrawal strategy and cost estimates for water treatment and reservoir management.

We found that the GreenGen site is an exceptionally good location for treatment of produced water, based on the low cost of treatment, proximity of point-of-use for the finished water to the treatment facility, and low costs for disposal of waste concentrate. More information is needed to determine if infrastructure placement relatively near the point of injection is appropriate for plume management over longer times. The cost and practical impact of regulations in China and Tianjin on concentrate disposal and other aspects of water production and treatment are unknown. Ultimately, realistic costs from Chinese treatment systems should be used to verify further cost estimates for this system.

Excluding enhanced oil recovery projects, only one large, subsurface carbon storage project has been deployed in the U.S.: the Illinois Carbon Dioxide Capture and Storage Project. It stored about 1,000,000 t of CO_2 between 2011 and 2014. The project does not include EWR or any attempt to manage reservoir storage by systematic water withdrawal. Storage reservoir performance is currently being evaluated. Early indications suggest that the plume expanded away from the injection well at a more rapid rate, was thinner, and utilized less of the storage reservoir than anticipated. Another, larger phase of the project is scheduled to begin in early 2016. It will be the first U.S. geologic carbon storage project to operate under the conditions of a UIC Class VI injection well permit. This level of permitting is now required of any large scale CO_2 storage project (Gollakota and McDonald, 2014).

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