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Validating subsurface monitoring as an alternative option to surface M&V - The CO2CRC's Otway Stage 3 injection

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Abstract

Future CO_2 storage projects will require Monitoring and Verification (M&V) operations at the CO_2 storage site to understand the behavior of the CO_2 plume, including the assurance that leakage of the CO_2 has not occurred. Current surface based monitoring technologies may be unable to yield sufficient resolution or accuracy. CO2CRC, in conjunction with its Australian partners, is developing the Otway Stage 3 Project to identify and validate sub-surface monitoring techniques and configurations as a key element of a risk-based M&V program in large scale CCS projects. Subsurface monitoring approaches will be tested on a plume of CO_2 from an array of monitoring wells. Primary monitoring methods will be pressure tomography and downhole seismic, although other modalities (gravity, electromagnetic) are also being considered.

Keywords: CO2 storage, containment, conformance, subsurface monitoring, pressure, seismic

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1. Introduction

Future CO_2 storage projects will require Monitoring and Verification (M&V) operations at the CO_2 storage site to understand the behavior of the CO_2 plume, including the assurance that leakage of the CO_2 has not occurred [1]. M&V programs may require measurements of the CO_2 plume behavior with wide spatial coverage, good spatial resolution

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and high temporal frequency, and subsequently may require regular or continuous surveys. M&V programs that rely largely on repetitive, surface-based surveillance (such as conventional reflection seismic) may be costly and may face logistical and societal obstacles in some circumstances.

CO2CRC, in conjunction with its Australian partners, is developing the Otway Stage 3 Project to identify and validate sub-surface monitoring techniques and configurations as a key element of a risk-based M&V program in large scale CCS projects. The project will inject CO_2 from a single injector well at the Otway site in western Victoria (Figure 1) [2]. Subsurface monitoring approaches will be tested on the resulting plume of CO_2 from an array of monitoring wells. Primary monitoring methods will be pressure tomography (including above-zone and injection modulation methods) and downhole seismic, although other modalities (saturation logging, electromagnetic) are also being considered. The project will scale up spatially from previous multi-well pilot projects (Frio [3], Nagaoka [4], Ketzin [5], and Cranfield [6]) towards more commercial scales, building on the experience of these projects.

While some aspects of the proposed monitoring methodologies are familiar in the oil and gas sector, the risks and regulatory requirements that need to be addressed in CCS are different. Permanently deployed, sub-surface monitoring tools are novel in this application and will need to be tailored to project risks and also to cost-effective technologies. Supplementing episodic surface monitoring with permanent subsurface monitoring of plume encroachment to a specifically targeted higher-risk area or zone, and therefore validating containment, may be a useful option: for example, migration of the plume towards a lease boundary may be a concern. A subsurface sentinel system could be designed to raise a warning flag and prompt a planned response, as well as adding to the storage system’s characterization of reservoir response and provide additional information to validate the site’s CO_2 containment.

The CO2CRC Otway Stage 3 project is currently progressing through standard design phases, with the scientific basis and facility design (including an appraisal well) being complete by early 2017.

The CO2CRC Otway site provides a proven setup for benchmarking and improving the proposed deep monitoring configuration. The site has been characterized in detail and tested for CO_2 storage in depleted gas fields and saline formations [1, 7, 8]. It has $90M of existing infrastructure and associated in situ value, greenhouse gas storage permits in place and a readily available resource of >450kt of CO_2 for Otway Stage 3 and future research.

The purpose of the CO2CRC Otway Stage 3 Project is to develop and validate methods of monitoring a CO_2 storage site using, as far as possible, only downhole equipment in wellbores. Monitoring of a CO_2 storage site is an essential operational obligation in CCS. Current surface-based monitoring techniques may have high continuing costs and may have additional societal and environmental costs. By 2020 Otway Stage 3 has an objective to have determined and demonstrated the most cost-effective CO_2 subsurface monitoring solution. We will produce a CO_2 plume analogous to a leakage event, to validate these high-resolution, real-time monitoring capabilities in the subsurface environment and provide a monitoring solution with minimal impact on communities that provides social and regulatory acceptance.

2. Project Design

The Paaratte Formation, a non-potable aquifer previously used for the Otway Stage 2 injections [7, 8], has been judged the most promising location for the storage reservoir, as it is well-understood from previous injections. The Paaratte is a heterogeneous saline formation comprising stacked reservoir and seal pairs at depths of 1300-1560 m (below mean sea level - MSL). At the site there is no clear structural closure and low dip to the strata (Figure 2). A migration route within the lower unit of the Paaratte has been chosen to provide a predictable plume distribution. The injection will probably be about 15kt, to reduce interaction with the CO_2 plume from the Otway Stage 2C experiment [11]. This is located in the same injection interval of the Paaratte but further to the East. Monitoring wells are tentatively positioned at the largest possible distances from the plume, given geological constraints. Vertical wells have been chosen for reasons of low cost and flexibility in future applications; but it is expected that results will be just as applicable to an industrial-scale project that could employ fewer, deviated wells to attain the same objectives.

Inverting the pressure signals from these monitoring wells [Section 5] will test the ability to locate the injector, taken as a surrogate for a leak. Once the injection ceases, pressure signals rapidly reduce but the plume can be sensed with standard inter-well interference tests between wells in the monitoring array [Section 5]. Seismic monitoring will utilize permanent sources at surface, combined with permanent geophone strings or optical fiber sensors in the monitoring wells (Section 6). Pulsed neutron logging at wells that contact the plume will be used to quantify saturation, and the existing buried array of surface geophones [9, 10, 11] will be used for standard 4D seismic to provide "ground truth" of the plume's shape and movement.

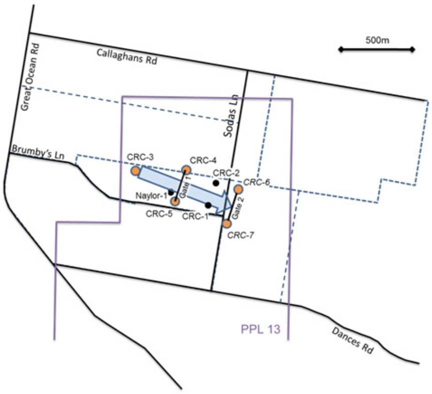

Figure 1 Preliminary injection and monitor well placement for the OSL within the existing Otway facility. Black lines indicate roads, blue dashed lines property boundaries, and purple lines the PPL 13 petroleum tenement. Filled black circles indicate the location of the existing wells, orange are proposed wells. Blue arrow indicates CO_2 migration direction (ESE) from the proposed CRC-3 injector.

3. Geological setting

The Paaratte Formation comprises the upper part of the Sherbrook Group Super Sequence. It is Campanian to Maastrichtian in age [12], and is defined by three units: (A, B and C [12]). These are distinguished on the basis of biostratigraphic age and paleo-depositional environment, ranging from pro-deltaic, upper-deltaic, to estuarine. Deposition evolved during the later stage of rifting and extension in the Otway Basin's history [13], and resulted in dominant half-graben development separated by the linkage of transfer fault blocks. The Otway Project site is located within one such fault block, bounded to the south by the Naylor South Fault, and bounded to the north by the Buttress and Boggy Creek fault complexes. The existing wells are sited near the crest of a structural saddle between the terminating fault zones (Figure 2). The proposed new injector, CRC-3, will be located 640 m west of the existing CRC-2 well, to take advantage of the structural gradient dipping down towards the west-north-west parallel with the main Naylor South transfer zone. (Figure 2).

There is significant offset across the Naylor South Fault at the Paaratte Formation level, such that the shallower units, B and C, are juxtaposed to the Timboon Sandstone fresh water aquifer above around -1350 m (MSL) (Figure 3). For this reason, Unit A, at the base of the formation, is the target for Otway Stage 3 Project activities in order to minimize any risk of interaction with the Timboon. There is a smaller synthetic fault, the "Naylor South Splay Fault", parallel to the Naylor South Fault. It is approximately 1500 m long with a maximum offset at the Paaratte level on the order of 15 to 30 m. This fault appears to die out below the top of the Paaratte Formation. Fault modelling was performed [14] to assess the fault seal potential across and along this fault and any impact it may have on CO_2 migration over the unit A interval. It was shown that the sealing properties of the splay fault, related to shale gouge ratio and juxtaposition, would probably be sufficient to prevent vertical migration of the plume from the Otway Stage 2C injection. However, juxtaposing sand units are more likely further west due to less throw along the fault. Consequently, the fault is probably horizontally transmissive in the vicinity of the CRC-3 proposed injection location. The storage container includes reservoir both north and south of the Naylor South Splay Fault and migration horizontally through this fault, therefore has no containment risk, yet would presents a demonstration of fault migration processes, very important for future CCS projects internationally.

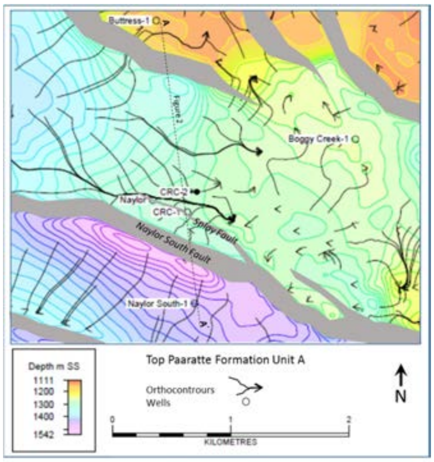

Figure 2 Sub-surface map with orthocontours (black arrows) representing the pathways of maximum structural gradient

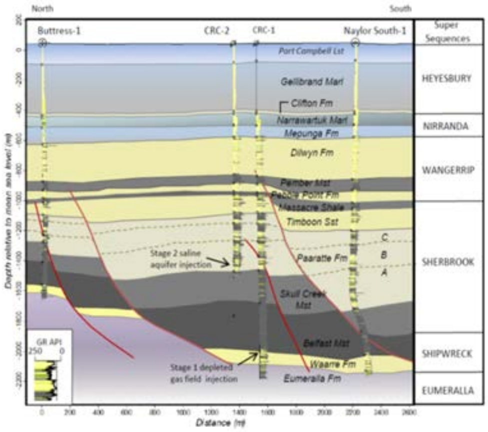

Figure 3 Structural and stratigraphic cross-section through the Otway Project site. Stage 3 will target the lower Paaratte Formation Unit A used for Stage 2.

Three fourth-order parasequences were identified within Unit A and were correlated across the study site as part of the Otway Stage 2 characterization effort [15]. These parasequences represent coarsening-upward depositional cycles separated by regional flooding events, giving rise to a stack of three potential reservoir/seal pair targets, abbreviated herein as PS 1, PS 2, and PS 3. Information about the seal continuity of the targets came from integrating well log and core data with extensive analogue studies. Deltaic to shallow marine systems were drawn from the work of (amongst others), [16 - 19]. Specific ranges for length and width of channel and mouth bar facies were derived from numerous analogue studies that were compared and summarized in [18]. This has led to the understanding that the reservoir architecture of the sands and shales are expected to be laterally continuous over the area modelled (10s Km), and therefore the parasequences are highly likely to be encountered in a similar staking pattern at the proposed CRC-3 location.

The current static geological modelling for Otway Stage 3 is focused on representing the key geological features and uncertainties that may affect plume containment and migration in the dynamic simulations. The main uncertainty investigated is the effect of variations in the structural dip away from well control, and the internal heterogeneity within each parasequence. For example, cemented low permeability baffles, that are a result of diagenetic dolomite in the proximal mouth-bar sandstones, will present source of heterogeneity in reservoir properties. Bounds on the lateral extents of these baffles investigated in the Otway Stage 2 models were 40 m to 200 m [15] and relied heavily on analogue work on the Frewens Sandstone within the Frontier Formation, Wyoming [20]. Recent seismic inversion of the Otway Stage 2C 4D survey data has improved the visualization of these geobodies (Glubokovskikh, pers. com.), and these data have been used in the uncertainty modelling work as part of the Otway Stage 3 Evaluate Phase.

The across-fault and fault-parallel hydraulic properties of the splay fault are also an important consideration. An orthocontour analysis of the structural horizons (black arrows orthogonal to structural contours in Figure 2) show a strong trend for a buoyant plume to migrate towards and along the structural high near the fault. The transmissibility and risks of across and up fault flow were modelled using PETREL^{TM} fault analysis module. The shale gouge ratio (SGR), which determines the amount of clay smearing throughout the fault, was calculated for each of the faults within the model. The across-fault transmissibilities were then modelled as a measure of fault seal potential. Across-fault juxtaposition of units was also characterized so that the location of probable leak points could be determined. Using this method, it was found the uncertainty with greatest influence is the translation of the SGR values to transmissibility multipliers. Determining SGR from the net to gross model of the reservoir means the root of the uncertainty lies with the assumptions made about volume clay (V-clay) interpreted at the petrophysical logs and how this is up-scaled to the reservoir. New petrophysical logs from CRC-3 appraisal well will inform the interpretation of V-clay as well as improve the understanding of reservoir dip and heterogeneity. In addition, a new source of information that may constrain uncertainty in the fault modelling is the Otway Stage 2B tests and the production test from the Otway Stage 2C perforation workover. Analysis of these tests is in progress. At this time, the interpretation and history match of the pressure data is still continuing, but it is hoped that results will guide characterization of the reservoir properties and the fault's hydrodynamic potential, and can further inform dynamical modelling.

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4. Dynamical modelling

The design of Otway Stage 3 is supported by extensive dynamic reservoir simulation of the injected CO_2 plume. These simulations are used to characterize the uncertainty surrounding the plume distribution and to make decisions concerning the location of the injection and monitoring wells. The model inputs have been calibrated to the extensive data collected during the previous injection tests at Otway in the CRC-2 well. Six unique geological models have been considered, with two cases for each of three dip angles between the proposed CRC-3 injection well and the existing CRC-1 and CRC-2 wells. The existing wells are up dip in the formation and in the expected flow direction of the plume. Four relative permeability curves have been also considered, along with possible values for fault transmissibility. The main focus has been on injection into parasequence 1.1 (PS 1.1) of the lower Paaratte A formation, which was also used for the Otway Stage 2C injection test in which 15,000 t of Buttress gas was injected at the CRC-2 well. PS 2.1, which was used for the Otway Stage 2B [7] and Otway Stage 2B extension [7] projects is also considered as a secondary target. Simulations for injection into PS 1.1 indicate that there is considerable uncertainty in the lateral spread and thickness of the CO_2 plume. Dip angle and relative permeability have a large impact on the distribution of CO_2 in the reservoir, while transmissibility of the splay fault has a large impact on only the part of the plume that contacts the fault. In particular, there is the likelihood of the CO_2 contacting and crossing the interior splay fault near the wells, though the amount of CO_2 that would migrate across the fault remains a key uncertainty. As the Naylor South Fault is interpreted to be sealing there is little chance of CO_2 migrating outside the fault block. Much of the uncertainty in the plume size and thickness can be mitigated by the early injection and well testing of the CRC-3 injection well. There is considerably less uncertainty in the pressure response expected both in the CRC-3 injection well and the array of remote monitoring wells. Across the full simulation analysis, there was just

±20% variability in the predicted pressure response, even for the most distant wells. This is due to the very high permeability and long correlation distance of geological heterogeneity in the Lower Paaratte A in PS 1.1.

5. Pressure monitoring

The range of possible pressure monitoring techniques can be divided into passive methods (inversion of leakage signals, earth tides) and active methods (involving time – modulated injection). The detection and inversion of pressure anomalies from leakage has been well-studied (e.g. [21, 22], and is promising for in-zone and above-zone monitoring.

One of the key features of pressure propagation in the subsurface is that it is relatively rapid, and therefore detectable at longer range. For the target reservoir with a permeability of order of $k = 10^{-12}$ m^2, D the hydraulic diffusivity of pressure (brine saturated rock) is about 10 m^2 s^{-1}. A typical propagation distance for pressure over time t would be of the order $(D\ t)^{1/2}$. For a time period of 1 hour this is around 200 m, while for a time period of a day the distance is around 1000 m. It is possible to make some simple estimates of the detectability of a point source leak by a single monitoring well completed in that zone. Using the line source solution for constant rate injection, the detectable leakage mass rate Q (for equivalent water volumes) can be estimated as

$$Q \approx \frac{P_{th}\rho_w 4\pi K h}{\mu_w(-\gamma - \ln(\frac{r^2\phi\mu_w c_t}{4Kt}))}$$

where P_{th} is the pressure detection threshold (1 kPa), ρ_w is the water density (988 kg m-3), h is the thickness of the monitoring formation (10 m), t is the detection time (100 days = 8.64×106 s), k is the aquifer permeability (10-12 m2 ~ 1 d), φ is porosity (0.2), C_t is total compressibility (0.73×10-9 Pa^{-1}), μw is the water viscosity (0.45×10-3 Pa s), r is the distance to the leak (200 m), and γ is Euler's gamma constant (≈ 0.5771). The values given are typical for the CO2CRC Otway project, and the result is Q ~ 1000 tonnes/year. For injection of CO_2-rich gas proposed at the Otway site, the density is 1/3 of the water density, and so the rates are correspondingly less. Thus for the likely well configuration for the project (Figure 1), in-zone detection of the pressure response will be practicable for quite low injection rates (1-10 tonnes per day). The key advantage over fluid sampling techniques is that the CO_2 plume could be detected a long way from the monitoring well. A variety of factors, especially temporal drift of gauges and geomechanical effects, could make slow changes of pressure harder to detect.

Pressure measurements at a single monitoring well cannot give directional information, but if the form of the leakage is assumed (e.g. wellbore transmission) then one can estimate the distance to the leak [23] and define a set of candidate locations [24]. Multiple monitoring wells clearly assist the inversion process, although the heterogeneity of the reservoir (as well as the unknown form of the leak) make this inversion challenging.

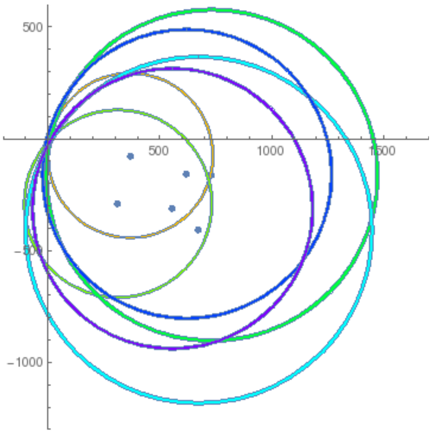

Figure 4 Inversion of injector location based on synthetic pressure data. The true injector location is at the origin, and the blue dots are the proposed monitoring well locations (Figure 1). For each of these wells, the coloured annulus represents the range of likely distance to the injector location. The intersection of these rings indicates the region of maximum likelihood for the injector location. The units of the axes are meters.

A simple scoping calculation illustrates the principle and feasibility of the method for our monitoring array. Using the single-phase pressure solution for constant rate injection (which is valid far enough away from the CO_2 injection well), one can generate synthetic pressure data for a proposed configuration of monitoring wells, allowing for some uncertainty in the average reservoir properties and adding some realistic noise. A simple approach takes the data at each monitoring well, and fits the injection time, rate and distance to the injector. The range of likely distances to the "leak" defines an annulus between two circles centered on that well, and the intersection of the annuli from multiple monitoring wells gives an estimate of the injector location. Figure 4 shows an example for a possible configuration of monitoring wells, for an injection of 150 tonnes per day for 100 days, where the actual injector location is at the origin. Depending on the degree of variation of the average reservoir permeability along the path between the injector and the monitoring wells (here assumed to have a normal distribution with a standard deviation of 5%), the inversion of the synthetic data locates the injector to within 50 m. In practice, the spatial variability of permeability in the selected reservoir interval is likely to be greater than this assumption, and a full geostatistical treatment will be used to assessment the accuracy of inversion.

The analysis of earth tide response also holds promise for plume monitoring even once the injection or 'leak' has ceased to be active. There has been extensive use of these measurements in hydrology and petroleum engineering to infer the compressibility of the formation (e.g. [25, 26]). The presence of CO_2 in the reservoir unit lowers the compressibility, and this is detectible if close enough to the monitoring well [27]. This type of analysis has been used on pressure data from the most recent test at the Otway site. Further theoretical developments and analysis of field data is required to test the effective range of investigation of this method.

Active pressure response methods, such as cross-well interference testing, have a long history in the petroleum domain. The concept is to inject or produce fluid in one well for an extended period of time, and observe the pressure response at another well location [28]. Analysis of the results can provide information about both the mobility-thickness product, and the porosity-compressibility-thickness product. Modulating the injection rate in time adds further information, and helps to limit the effect of various unrelated slow drifts that are often observed in pressure signals.

In these tests, properties are averaged not just between the wells, but over a region around each well, the size of which depends on the length of the test. The existence of a CO_2 plume in the reservoir will obviously modify the compressibility in that region, and should thus affect the results of an interference test. This could be done in a time-lapse mode – contrasting the results before and after CO_2 injection and migration – and thus potentially estimate plume location, or validate model predictions [29]. This would help distinguish between brine leaks (which also produce a pressure signature) and CO_2 leaks, and overcome the ambiguity of slow above-zone pressure buildup observed in some field examples, where the source of the pressure increase is difficult to discern.

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6. Seismic monitoring

Preliminary results of Otway Stage 2C of the Otway project [9-11] prove the high efficiency of surface seismic in detection and characterization of the injected CO_2 at the project area. In general, we anticipate similar performance for the new injection. However, the new seismic monitoring program has much broader scope, which can be split into three major components, according to their objectives:

1. providing a reliable time-lapse image of the injected CO_2 to verify and calibrate other monitoring modalities: pressure and permanent seismic monitoring – this will be achieved with the existing buried surface array of geophones;
2. high-resolution imaging of the CO_2 plume heterogeneities and development of the rock physics model for the quantitative interpretation of the seismic monitoring data.
3. development of cost-effective downhole-based seismic monitoring techniques.
4. Otway Stage 2C provides convincing evidence that the seismic contrast induced by the replacement of some fraction of the pore brine by CO_2 is sufficient for detection using the existing buried receiver array. To compliment and ensure the surface seismic performance, we will acquire 4D VSP using conventional geophones in some of the monitoring wells.

A relatively dense well network surrounding the injector increases the feasibility of cross-hole reflection tomography to retrieve subtle features of the CO_2 plume. Recently developed downhole instrumentation provides repeatable high-frequency signals (up to ~4kHz) at the target depths (~ 1500m). Thus Otway Stage 3 provides a unique opportunity to characterize the CO_2 plume over a range of seismic frequencies, corresponding to different spatial scales. Potentially, these data may form the basis for a rock physics interpretation of the seismic monitoring data: saturation distribution, effective gas column height, characteristic size of a gas patch, and the interaction of the CO_2 plume with a fault.

In compliance with the main objective of Otway Stage 3, we will explore capabilities of the monitoring system consisting of downhole seismic receivers and a limited number of near-surface permanent sources. Possible components of such systems are being tested in the framework of Otway Stage 2C of the project [11]. Distributed acoustic sensors [10] in all of the wells will be a primary receiver array. Notwithstanding its rapid development, optical fibre (used as an acoustic sensor) is still an immature technology. A set of conventional geophones – either tubing- or casing-conveyed – will secure the performance of the permanent monitoring system.

7. An early appraisal well

The spatial scale of this experiment is small by commercial standards and the geology is well understood and unlikely to show much spatial variability between the existing and planned wells. However, the relatively small spatial scale, and the presence of faults and pre-existing CO_2 plumes, means that it is desirable to have a high degree of certainty about some key reservoir parameters. The most important of these are dip, relative permeability, and overall pressure communication across the monitoring array. Accordingly, to minimize risk, the proposed injector CRC-3 will be drilled early in 2017 as an appraisal well. An extensive Formation Evaluation Plan including coring, wireline logging and an injection test will be undertaken to inform the final choice of locations for the wells in the monitoring array.

8. Conclusions

Thus far, feasibility studies for validating a subsurface monitoring alternative at the CO2CRC Otway Research Facility have presented a viable case, considering the likely CO_2 distribution and selected monitoring modalities examined. The next task is locating the monitoring wells around the expected plume footprint, with the properties of the splay fault being highly relevant to this design decision. Achieving and interpreting interference tests, when highly compressible gas is adjacent to the wells, needs to also be modelled before commencing this experiment. Data from the CRC-3 appraisal well, being drilled in February 2017, will greatly assist in reducing these uncertainties.

Success of this Otway Stage 3 Project will provide an alternative option for monitoring CO_2 storage in a cost effective manner, particularly for regions where surface based operations are challenged by environmental, socio-political or accessibility factors.

Acknowledgements

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