Opportunities for underground geological storage of CO2 in New Zealand - Report CCS -08/3a - Waikato coal resource, reservoir modelling

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ABSTRACT

The Waikato coalfields in the North Island of New Zealand are currently being assessed for coalbed methane development. The Eocene coalfields have significant subbituminous coal deposits that contain biogenically-sourced methane. The Huntly coalfield, one of the Waikato coalfields, has previously been characterised to have relatively low to moderate total gas contents (2 - 4 m^3/tonne) that are >90% methane (CH_4) in composition. The CO_2 holding capacity is relatively high (18.0 m^3/tonne) compared with that of CH_4 (2.6 m^3/tonne) and nitrogen (N_2) (0.7 m^3/tonne) at the same pressure (4 MPa; all as received basis).

This study has been conducted to assess the potential of the Waikato coalfields for CO_2 sequestration and enhanced coalbed methane (ECBM). Three locations were selected for investigation (1) Ruawaro: a medium depth, moderate-low permeability area with good gas content, (2) Mangapiko: a deep, high permeability area with low gas content, and (3) Ohinewai: a shallow, moderate-low permeability area with very low gas content and thick coal seams. 3D scenarios with a 9-spot well design were conducted using a new module for the TOUGH2.2 reservoir simulator (ECBM-TOUGH2.2) that can handle non-isothermal, multi-phase flows of mixtures of water, CH_4, CO_2, N_2 and H_2S.

Scenarios were performed on 80, 160 and 320 acre well spacing, with both stimulated and unenhanced wellbores. The initial phase of the simulation was five years of gas production, followed by different injection scenarios using CO_2, flue gas, gases from underground coal gasification (UCG) and water. These were injected at rates of 5, 10 and 20 tonne/day for up to 10 years. To assess seal integrity and reservoir storage ability, monitoring wells were spread across the surface layer to capture any leakage of injected gases.

For CBM production scenarios stimulated wells perform substantially better than unenhanced wellbores. An increase in well spacing increases the time until peak production is reached. The peak production rate is lower for wells with increased well spacing however the peak rate is maintained for a longer period of time. Optimal well spacing will be decided by long term field development plans, land access and economics.

CO_2 sequestration appeared to be most successful in the Ruawaro and Mangapiko scenarios. Where injection gas breakthrough occurred, it was earlier at the Mangapiko location than at the Ruawaro, for all scenarios, because of the higher permeability. As such, a larger well spacing maybe desirable at this location. For the Ruawaro scenarios CO_2 never reached the well furthest from the injection well, hence production gas quality may only be affected in the wells closest to the injector. The injection of CO_2 had little enhancement on CH_4 production at either location. While injecting at rates of 5 and 10 tonne/day seems feasible, injecting at a rate of 20 tonne/day caused model failure in all scenarios.

Flue gas injection scenarios had significant enhancement on CH_4 production in all scenarios. However, breakthrough of N_2, the primary component of flue gas, is almost instantaneous in the closest well to the injection well and quickly reaches production rates similar to those seen for CH_4. CO_2 also breaks through faster in the flue gas scenarios than for pure CO_2 gas injection despite being injected in smaller quantities. The selected rate of injection and the well spacing will depend on the requirements of the end user as well as the number of production wells online, producing relatively pure methane, available for blending gas quality.

Injection of flue gases generated from UCG produced results very similar to those seen for the flue gases from gas fired generators. Scenarios where water was injected into the coal

seam clearly showed that waste water re-injection wells need to be away from the drainage area of the coal seam, which may or may not be confined to the coal layer.

Wellbore pressure for all scenarios shows a dramatic increase when injection commences. After the initial increase, continued injection of CO_2 causes a small but steady increase in well block pressure while flue gas injection shows a steady decrease. Because of the greater permeability, injection pressures at Mangapiko reach only half those seen for the Ruawaro location. The wellbore temperature also undergoes instantaneous change with flue gas injection causing considerably higher temperatures than pure CO_2 injection. An understanding of potential wellbore pressures and temperatures will be essential in field infrastructure requirements.

The results clearly identified the Ruawaro and Mangapiko locations as being suitable for further investigation. In contrast, the Ohinewai location can be excluded as, aside from being unsuitable for CBM production because of very low gas content, the models showed leakage of injected gases to the surface.

KEYWORDS

Carbon dioxide, storage sequestration, Waikato coal modelling.

1.0 INTRODUCTION

1.1 SCOPE AND OBJECTIVES

This report presents part of the findings of Task 1.2 (Objective 1) of the Carbon Capture and Storage (CCS) Programme. It presents the results of enhanced coalbed methane (ECBM) simulations investigating the potential for ECBM within the Waikato coalfields. This report is a component of "Opportunities for underground geological storage of CO_2 in New Zealand - Waikato coal resource " and hence should be read in conjunction with Edbrooke et al. (2009) - Report CCS-08/3.

The scope of this report is:

- To investigate the potential for CO2 sequestration and ECBM at several locations with 3D models illustrating possible field development in the Waikato coal system.
- To investigate the effects on CH4 production rates of:
  - depth
  - well spacing
  - coal properties
  - wellbore enhancement
  - injection rate
- To predict gas breakthrough times and enhancement of CH4 production following the injection of both pure CO2 and flue gases after a period of CBM production.
- To assess seal integrity by monitoring for potential CO2 leakage.
- To identify areas for further study.

Report CCS-08/3 (Edbrooke et al. 2009) further assesses the potential for CO_2 storage in Waikato and King Country coal seams by:

- Providing an overview of the Waikato coal resource and commenting on the potential storage options;
- Investigating the properties of Waikato coals relevant to their CO2 storage potential;
- Estimating carbon dioxide storage capacity for identified areas of unmineable Waikato coal, and the King Country coalfields.

1.2 REPORTING

This report is one of a series of reports commissioned by the Foundation for Research, Science and Technology (FRST) and funded by a government and industry backed CCS Steering Group. GNS Science, with major partners the University of Auckland and CRL Energy, is conducting an initial assessment of the feasibility of subsurface storage of CO_2 in both the Waikato and onshore Taranaki regions. The CCS report series is listed in Table 1.1, cross-referencing the report numbering system with specific programme tasks as outlined in the FRST contract (C05X0707).

Potential storage options being evaluated in the Waikato region include coal seams (Report CCS-08/3; Edbrooke et al. 2009b, and this report) and deep formations in the onshore (Report CCS-08/2; Edbrooke et al. 2009a) and offshore regions (Report CCS-08/4; Stagpoole et al. 2009). Additional opportunities evaluated in primarily the onshore Taranaki

Basin include: a desktop overview considering storage options in coals, deep formations, depleted oil and gas fields, and potential enhanced oil and gas recovery projects (Report CCS-08/5; King et al. 2009); technical reviews of both Paleogene (Report CCS-08/6; Higgs 2009) and Neogene (Report CCS-08/7; Strogen et al. 2009) reservoirs in the onshore region; and reservoir simulation results to test the storage capacity in the offshore Maui and onshore Cheal fields (Report CCS-08/8; Archer et al. 2009) The global technologies available for the capture, transport and injection of CO_2, (Report CCS-08/9; McCurdy et al. 2009) and methodologies suitable for CCS risk assessment (Report CCS-08/10; Gerstenberger et al 2009), and the monitoring and verification of injected CO_2 plumes (Report CCS-08/11; Bannister et al. 2009), are also reviewed in a New Zealand context. The overall aim of the research is to help major CO_2 emitters and the government develop policy and implement mitigation strategies, paving the way for pilot-scale projects to capture carbon dioxide and store it underground in geological formations. The primary conclusions and recommendations for storage opportunities from this programme are presented in an overview report by Funnell et al. (2009).

Table 1.1 Listing of companion volumes to this report.

Report title	Report #	Task
Waikato and onshore Taranaki Overview	CCS-08/1	1.4, 2.4
Onshore Waikato Region	CCS-08/2	1.1
Waikato Coal Resource	CCS-08/3	1.2
Waikato Coal Resource – Reservoir Modelling	CCS-08/3a	1.2.3
Offshore Waikato Region	CCS-08/4	1.3
Onshore Taranaki Overview	CCS-08/5	2.1
Onshore Taranaki Paleogene Reservoirs	CCS-08/6	2.2
Onshore Taranaki Neogene Reservoirs	CCS-08/7	2.2
Taranaki Petroleum Fields	CCS-08/8	2.3
Technical Reviews; Capture, Transport and Injection	CCS-08/9	3.1
Risk Assessment Methodologies	CCS-08/10	3.2
Monitoring and Verification Methodologies	CCS-08/11	3.3

1.3 BACKGROUND

The question of global warming, and more importantly the issue of what might be driving it, is still being debated amongst some in the scientific world. However, it is becoming increasingly obvious that mitigation measures, to reduce the impact of increasing greenhouse gases on our planet, should be implemented immediately. Energy efficiency, conservation, and increasing renewable energy sources are the easiest and unquestionably should be amongst the first mitigation measures to reduce greenhouse gas emissions. The primary goal of the United Nations Framework Convention on Climate Change (UNFCCC), as part of a broad portfolio of mitigation measures aimed at stabilizing greenhouse gas concentrations in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate system, is an 80-90% reduction in power station emission profiles (IPCC 2005).

Under conditions of the Kyoto Protocol, to which New Zealand is a signatory, nations are required to limit their total emissions of greenhouse gases (GHG) to 1990 levels, or a proportion of their 1990 levels, over the first commitment period. For New Zealand this means we must either pay for the volume of greenhouse gases emitted in excess of 1990 levels or reduce emissions to 1990 levels over the period 2008 to 2012. Since 1990, however, there has been a significant increase in New Zealand's greenhouse gas emissions, with the largest increase in levels of CO_2 emitted by the energy sector, specifically related to combustion of fossil fuels for domestic transport and electricity generation from thermal power stations. Yet, the continued use of fossil fuels is necessary, in the medium term at least, for a number of critical economic and strategic reasons. These include the sunk cost investment in existing infrastructure, the future cost (financial and/or environmental) of transferring to alternative energy sources, the rapid growth in demand for energy, the need for energy supply security, the need to maintain economic competitiveness with other nations, and the fiscal benefits of exploiting our own endowment of very high-value natural resources.

Underground storage or geological sequestration (geosequestration) of CO_2 is increasingly gaining recognition throughout the globe as a method for mitigating and reducing greenhouse gas emissions, primarily from the energy sector (IPCC 2005). Otherwise known as carbon capture and storage (CCS), this involves the capturing and separation of CO_2 from flue gases emitted from a stationery greenhouse gas source, transporting and injecting the CO_2 underground, and storing (or sequestering) it for periods sufficiently long to mitigate the impact of CO_2 on climate. While geological sequestration is a relatively new and innovative solution to reducing greenhouse gas (GHG) emissions; it exploits existing technologies for the separation of CO_2 from flue gases and for disposal and safe storage of CO_2 in the ground.

The changing of key market drivers worldwide has resulted in the exploration for, and development of, unconventional energy reserves such as coalbed methane (CBM), i.e. methane naturally occurring within coal seams. Although CBM has been extracted from high rank coals for at least the past two decades, until the success of the Powder River Basin, U.S.A. low rank coals containing biogenic methane gas have not been thought to contain sufficient CBM to be economically producible. Natural gas (methane – CH_4) is an important source of clean fossil-fuel energy that is experiencing growing demand in New Zealand. At the same time there has been a reduction in supply from existing conventional natural gas fields. This has prompted investigation for CBM potential in New Zealand (Hayton et al., 2004; Johnson, 2004; Manhire and Hayton, 2003; Moore et al., 2004; 2002; Pope et al., 2004; Stepanek, 2008; Twombly et al., 2004).

Concurrently, there is also increasing concern over the environmental impact of anthropogenic gas emissions, particularly carbon dioxide (CO_2), with targets and taxes being implemented to decrease gas release to the atmosphere. With coal, oil and natural gas currently supplying around 85% of the world's energy requirements, together with the abundance of fossil fuels and the significant infrastructure already in place, it is likely that burning of fossil fuels will continue for at least 25 to 50 years (Kaldi and Cook, 2006). As such, attention has turned to the capture and storage of CO_2 in geological structures; one option being the sequestration of CO_2 into deep, unmineable coal seams, with the possibility of enhanced production of coal bed methane (ECBM).

Unfortunately the cost incurred for the separation of CO_2 from flue gases currently makes CO_2-ECBM uneconomic (Sander and Allison, 2008). As such, the injection of untreated flue gases is also being considered. This both enhances CBM production and sequesters some CO_2, but has the side effect of early breakthrough of nitrogen (N_2), which is the major component of flue gas. Field trials into the effectiveness of ECBM are underway, or are in the planning stages, in many countries including Australia, Canada, Japan, China, Poland and the USA (Connell, 2008a; Damen et al., 2005; Hamelinck et al., 2002; Mavor et al., 2004; Ohga et al., 2005; Reeves et al., 2004; Shi and Durucan, 2005b; Wong et al., 2006).

In this study we investigate the potential for CO_2 sequestration and ECBM in the New Zealand context. The Waikato coalfields have been previously identified as a potential site for sequestration (Field et al., 2006; Zarrouk and Moore, 2008). Several sites within the Waikato coalfields were selected for closer examination by ECBM simulations using the TOUGH2.2 reservoir simulator.

1.4 LOCATION

The Huntly coalfield, part of the Waikato coalfields (Figure 1.1), is currently being assessed for coalbed methane (CBM) development (Mares and Moore, 2008a; 2008b; Stepanek, 2008; Twombly et al., 2004). One of the main point sources of anthropogenic CO_2 in the North Island of New Zealand is the Huntly thermo-electrical power station. This power station sits on top of large coal reserves and is located around 10 km from the CBM assessment site. The Waikato coalfields are being considered for future injection and sequestration of CO_2 and for ECBM (Edbrooke et al., 2007; Funnell et al., 2009; Zarrouk and Moore, 2007; 2009).

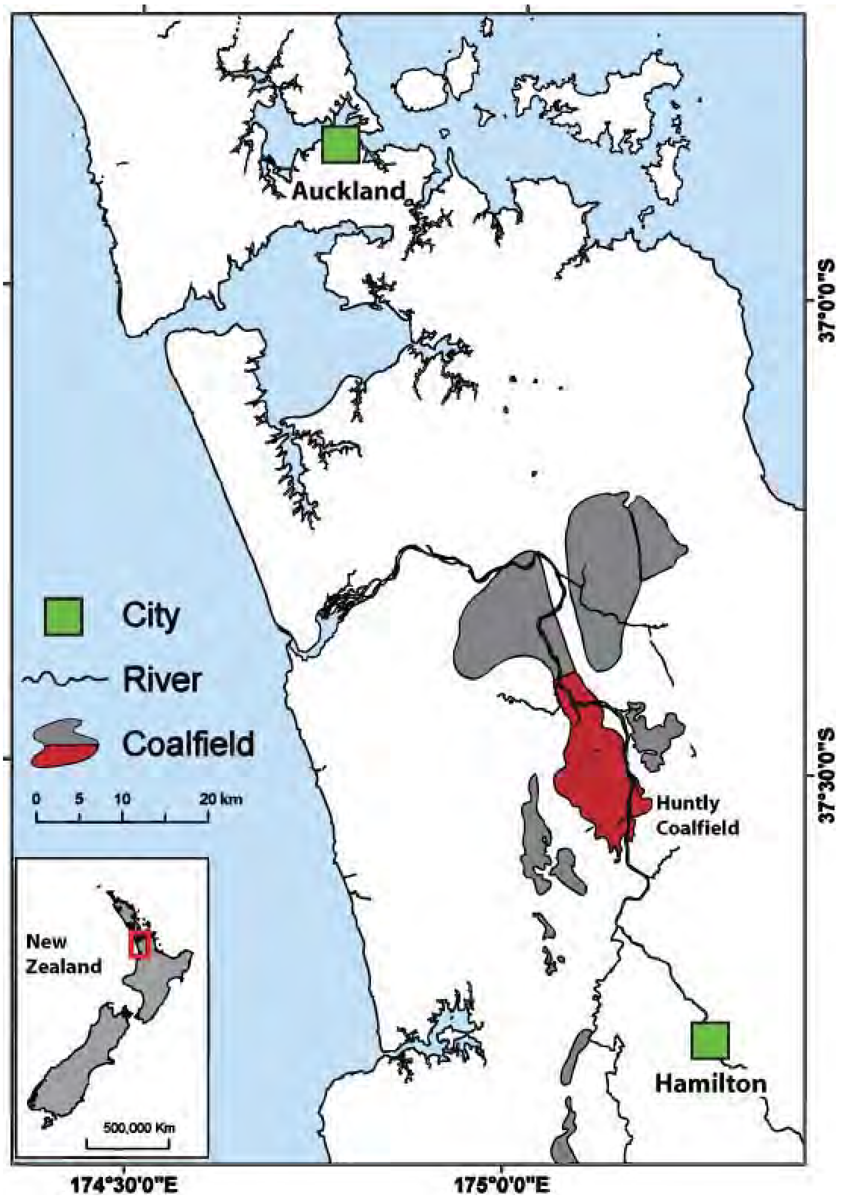


Figure 1.1. Location of the Waikato coalfields, coloured grey, with the Huntly coalfield coloured red, North Island, New Zealand (Mares and Moore, 2008b).

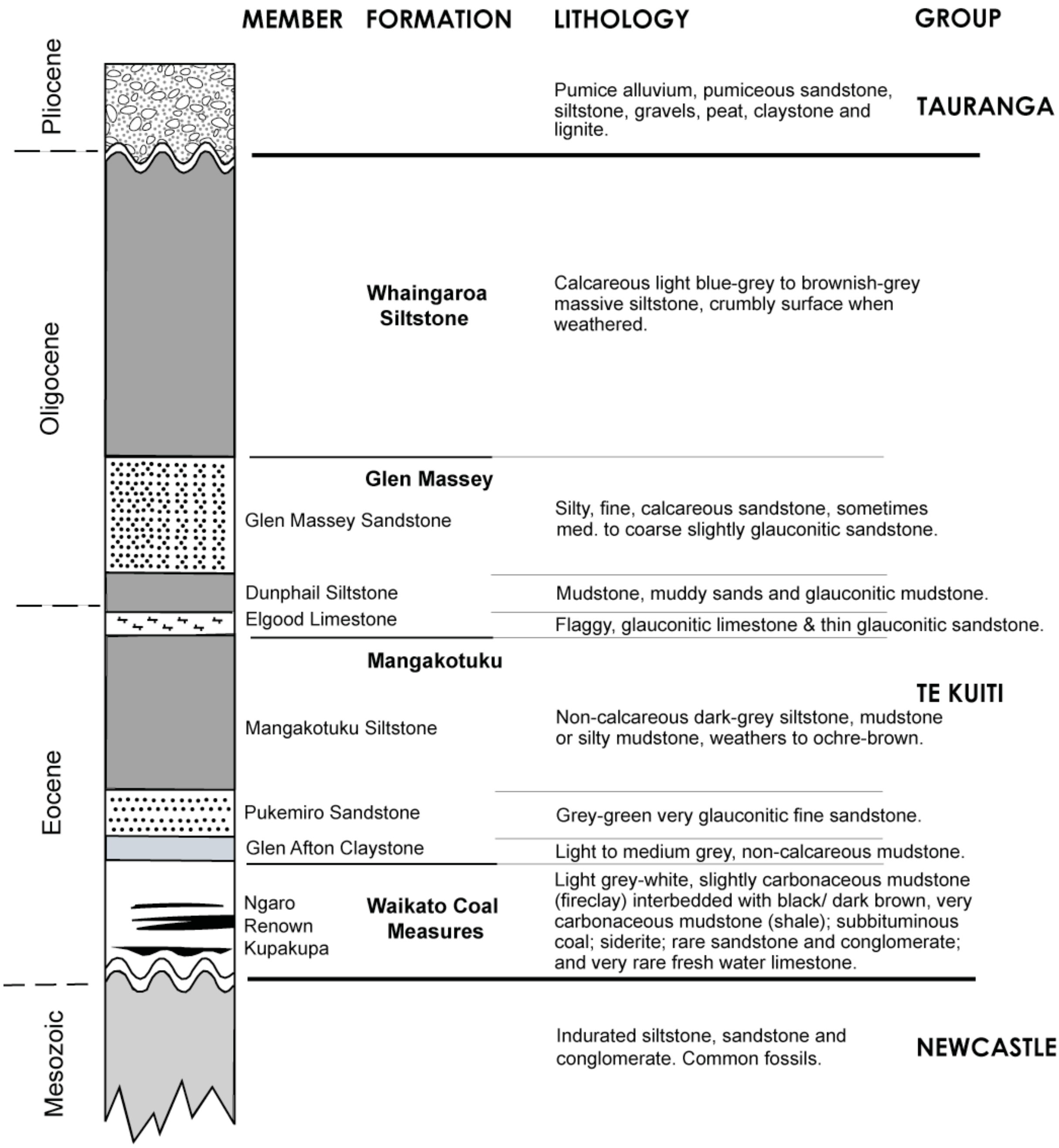


Figure 1.2. Stratigraphic column showing typical stratigraphy of the Huntly coalfield, New Zealand (Mares and Moore (2008b) edited from Hall et al. (2006)). The three coal seams in the Waikato Coal Measures are the Ngaro, the Renown and the Kupakupa.

The Waikato Coal Measures occur throughout the Huntly coalfield and are comprised of a number of coal seams, with the Renown and Kupakupa seams currently being targeted for mining and CBM (Mares and Moore, 2008b). The coal measures are typically 50 – 100m thick and are dominated by claystone and siltstone lithologies (Kirk et al., 1988). Above the Waikato Coal Measures are thick sequences of mudstones and siltstones which more than likely act as an effective seal (cap rock) for hydrocarbons and CO_2 (Figure 1.2).

The Eocene coals are subbituminous C to A in rank, with reported vitrinite reflectance's (%R_o) ranging from 0.34 to 0.53%, and are thought to have formed in a transgressive, fresh water, fluvial environment (Edbrooke et al., 1994; Mares et al., 2008a; 2008b; Newman et al., 1997; Twombly et al., 2004). The Renown seam tends to be located in the upper half of the coal measures and is generally less extensive, more split and thinner (<8m) than the

Kupakupa seam. The Kupakupa seam, found in the lower half of the coal measures, is typically 3 – 12 m in thickness, occasionally exceeding 20 m. Generally the Kupakupa is separated from the Renown seam by approximately 20 m of interburden, although in a few locations the two seams merge (Edbrooke et al., 1994; Newman et al., 1997). Discontinuities from original depositional processes have a major influence on the reservoir geometry and any ECBM project will have to take into account such reservoir geometry.

The depth of the coal beds range from essentially zero at the sub-crop to over 850 m in the most northern parts of the coal field (Edbrooke et al., 1994). The present target depths for CBM production in the Huntly coal field lie between 350 and 600 m. These depths are dictated by the depth of local underground mining (to depths of approximately 300 m) and the significant reduction in permeability below 600 m. Only normal faults exist in the coalfield and these are thought to all have occurred after deposition of the coal measures (Hall et al., 2006). Major faults (>20 m throw) occur about every 2 - 5 km and most of these trend northeast-southwest (Edbrooke et al., 1994; Hall et al., 2006). The cleat system has been determined to be sub-parallel to the strike of the normal faults (Cameron, 1995).

Three locations were selected for this study, as shown if Figure 1.3. The Ruawaro and Mangapiko locations are from different fault blocks of the Huntly coalfield while the Ohinewai location is situated in the nearby Waikare coalfield.

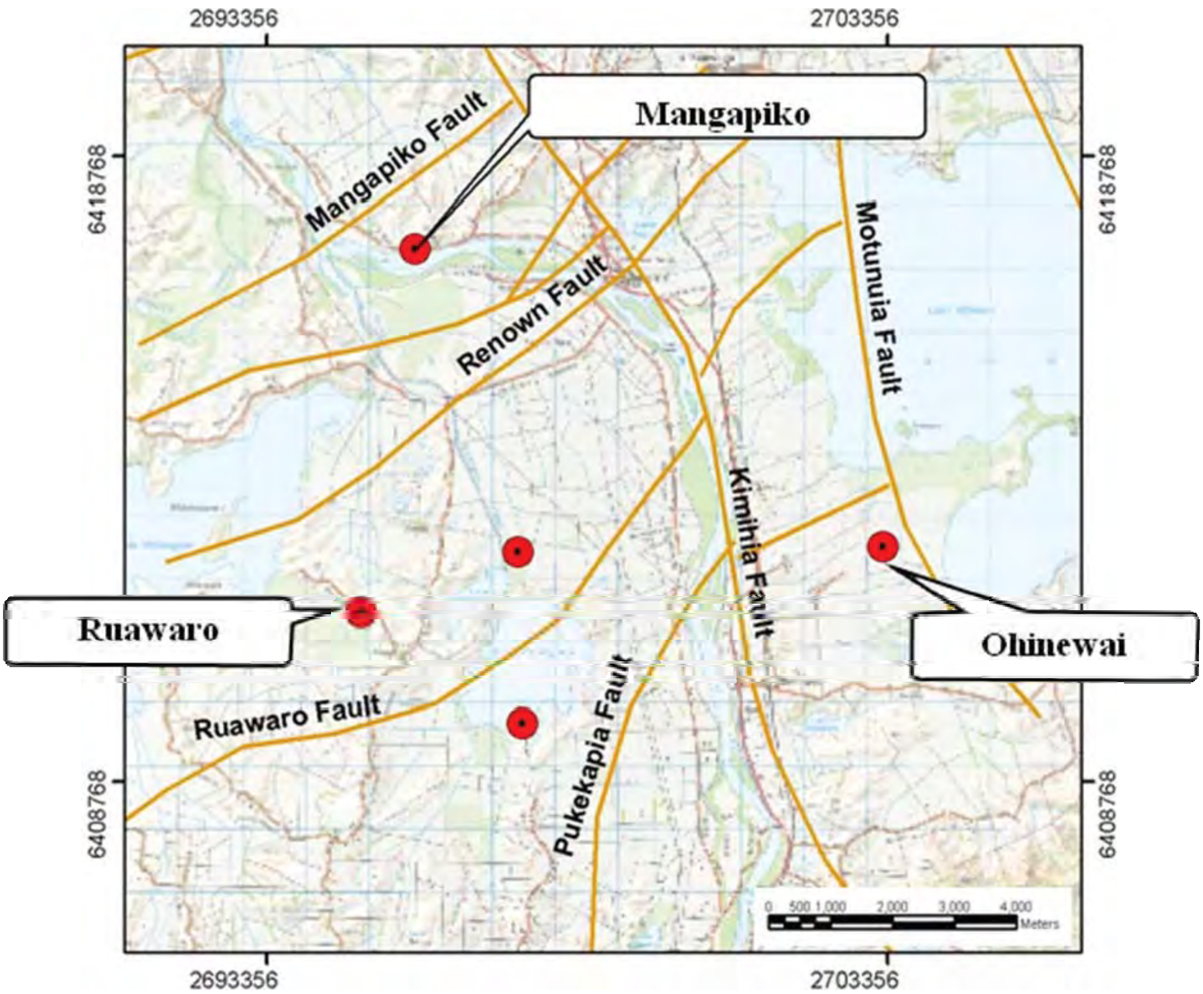


Figure 1.3. Locations used in this study: Ruawaro, Mangapiko and Ohinewai. Figure produced by Carlos Galceran of Solid Energy New Zealand Ltd (2007).

2.0 LITERATURE REVIEW

2.1 GAS ORIGIN

Coal seam gas is generated in coals by two different processes, biogenic and thermogenic (Rice, 1993). Biogenic gas is generated by the decomposition of organic matter by microorganisms and is generally restricted to shallow depth conditions with low temperatures (typical low rank coal conditions), although in some situations can have a complicated genesis. Biogenic gas is predominately CH_4 in composition. Alternately, thermogenic gas generation occurs at higher temperatures and pressures (i.e. with increasing coalification) as a result of devolatilization of the coal, with the most common byproducts being CH_4, CO_2 and water (Rice, 1993).

Vitrinite reflectance is used as a measure of thermal maturity in coal. Coals possessing a vitrinite reflectance (%Ro) below 0.6% primarily generate methane biogenically, whereas thermogenic methane generation predominates in coals with %Ro greater than 0.6% (Clayton, 1998; Flores, 1998; Rice, 1993). The %Ro of subbituminous coals is around 0.4 - 0.6% (Taylor et al., 1998), as mentioned previously the coal from the Waikato coal fields are subbituminous C to A in rank (Edbrooke et al., 1994; Newman et al., 1997) and have been found to have %Ro of 0.34 - 0.53% (Edbrooke et al., 1994; Mares et al., 2008a; 2008b; Newman et al., 1997; Twombly et al., 2004). As such, the method of coal seam gas generation is clearly biogenic.

Biogenic gas can be generated via two different pathways, CO_2 reduction and methyl-type fermentation:

Microbial reduction of CO_2: $$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \quad (2.1)$$

Acetate fermentation: $$CH_3OOH \rightarrow CH_4 + CO_2 \quad (2.2)$$

(Rice, 1993; Smith and Pallasser, 1996). It has been suggested that the depth of burial and the age of the organic rich material are regulating factors on the method of generation with fresh, near surface sediments generating gas via both pathways and deeper sediments mainly via CO_2 reduction (Rice, 1993). The dominant pathway can be identified by isotopic analyses (Smith and Pallasser, 1996) and the gas produced in the Waikato has been shown to be created by CO_2 reduction (Butland and Moore, 2008; Mares and Moore, 2008b; Moore and Butland, 2005).

Additionally, there are two different stages of biogenic gas generation. In early stage generation the gas is formed early in the burial history of low rank coal and is infrequently preserved if there was rapid deposition. Gas generated in recent times, known as late stage or secondary biogenic gas, is a result of bacteria being introduced to the coal, after burial and coalification, via active groundwater systems. This accessibility also suggests that reasonable permeability should exist within the seam (Rice, 1993; Scott et al., 1994). Carbon isotope data and the high CH_4 contents, averaging >90%, present in the Waikato indicate that the gas is primarily of secondary biogenic origin (Butland and Moore, 2008; Mares and Moore, 2008b; Moore and Butland, 2005).

2.2 GAS STORAGE

Gas is stored by the coal in four basic ways: (1) as limited free gas within the micropores and cleats (fractures) of the coal; (2) as dissolved gas in water within the coal; (3) as adsorbed gas held by molecular attraction on coal particle, micropore, and cleat surfaces; and (4) as absorbed gas within the molecular structure of the coal (Yee et al., 1993). The theoretical maximum amount of gas a coal can hold is tested by adsorption analyses, while the amount of gas actually held within the coal is measured by desorption (Diamond and Schatzel, 1998; Hayton et al., 2004). By comparing the results the saturation of the reservoir can be estimated. Stricker and Flores (2002) in their work on coals from the Powder River Basin found that coal beds of subbituminous B rank or lower are frequently undersaturated. Twombly et al (2004) and Butland and Moore (2008) found this to be true in the Waikato.

Later studies on the Huntly coals revealed that the results of isotherm analyses were significantly affected by temperature and moisture content (Moore and Crosdale, 2006) and that collecting fresh isotherm samples from the field site, rather than weeks or even months later, yielded lower gas adsorption capacities (Crosdale et al., 2008). These discoveries resulted in a considerable improvement in saturation calculations for the Huntly coalfield with the implications of underestimating gas adsorption capacity being highlighted by Mares et al. (2008a). It must be acknowledged that there is still significant variation in gas content and gas holding capacity both within the same field and even within the same seam hence sampling programs should be designed to capture this variation (Mares and Moore, 2008a; 2008b; Mares et al., 2008a; Moore et al., 2008).

The ability of a coal to store gas is a function of pressure, temperature, mineral matter, moisture, rank, petrographic composition and the different gases present (Montgomery, 1999; Yee et al., 1993). It has generally been accepted that gas sorption capacity increases with increasing pressure, which in turn is partially related to increasing depth as well as changes in temperature and rank. Increases in temperature result in gas favouring to be in the free rather than the sorbed state (Yee et al., 1993). Temperature with depth profiles have been produced for the Huntly coalfield by Zarrouk and Moore (2007). Some studies have shown that gas adsorbs to the organic components of coal, with mineral matter acting as a diluent, resulting in gas contents decreasing with increasing inorganic material (Butland and Moore, 2008; Laxminarayana and Crosdale, 2002; Mares and Moore, 2008b; Wang, 2007; Warwick et al., 2008). However, gas content variation in coal with <10% ash yield is still of significant proportions. When ash yield is low it is more likely that the majority of elements are organically bound within the coal rather than being present as mineral matter (Li et al., 2007; Newman et al., 1997). As the Huntly coals generally yield less <5% ash, mineral matter is not thought to be a major control (Mares and Moore, 2008b).

Inherent moisture is greatest in low rank coals (Ward and Barnsley, 1984) and laboratory experiments have demonstrated that the CH_4 sorption capacity of low to medium rank coals is strongly suppressed when the coals are initially saturated with moisture, as compared with the CH_4 capacity of the same coal on a dry basis (Crosdale et al., 2008; Levine, 1992). It is thought that moisture influences gas holding capacity by either competing with gases for adsorption sites or blocking access to some of the micropores (Bustin and Clarkson, 1998; Day et al., 2008b; Mares et al., 2008b; McElhiney et al., 1993).

Two different trends have been recognized between gas sorption and rank. One is U-shaped with a minimum at high volatile bituminous A rank, believed to be created by the initial presence of macroporosity which then collapses due to physical compaction followed by an increase in porosity again at higher ranks, due to the creation of secondary porosity by devolatilization of part of the coal structure. In the other CH_4 sorption increases with rank (Levine, 1993; Yee et al., 1993). Caution must however be exercised as changes in rank relate to changes in many other properties.

Vitrinite rich coals have been generally been found to have greater CH_4 adsorption capacity than inertinite rich coals for coals of the same rank (Crosdale and Beamish, 1993; Crosdale et al., 1998; Lamberson and Bustin, 1993) and vitrain rich coals greater adsorption than fusain rich coals (Warwick et al., 2000). It has been reported that bright or banded coals (high vitrinite, low ash) have greater micropore volume than dull coals (high inertinite, high ash) of the same rank (Clarkson and Bustin, 1996; 1999; Crosdale et al., 1998; Lamberson and Bustin, 1993) and that vitrinite has a greater micropore capacity than other macerals (Unsworth et al., 1989). New Zealand coals are typically high in vitrinite (Beamish et al., 1998; Butland and Moore, 2008; Mares et al., 2008b; Newman et al., 1997). The importance of this link between microporosity and bright coals lies in the observation of Clarkson and Bustin (1999) for the Gates formation coals, who suggested that micropore volume exerts primary control upon high pressure adsorption of CH_4 and CO_2 gases. In other studies, some of the gas variation has been associated with macroscopic texture such as the degree of vitrain banding (Butland and Moore, 2008; Flores et al., 2001; Mares and Moore, 2007; Mares and Moore, 2008b; Moore et al., 2001; Stricker et al., 2006), although the relationships are still poorly defined and certainly not universal (Butland and Moore, 2008).

Coal seam gas generally is composed of a mixture of CH_4, CO_2, N_2 and heavier hydrocarbons (Clarkson and Bustin, 2000). The gases do not sorb independently and can be competing for sorption sites. CO_2 is sorbed preferentially to CH_4 which is in turn greater than N_2 (Yee et al., 1993). The greatest percentage composition of CH_4 exists in high and low rank coals, with highly variable hydrocarbon composition at intermediate coal ranks (Clayton, 1998).

2.3 GAS TRANSPORT

For a coalbed methane prospect to be successful there must have been gas generation, must be capacity for gas storage and there must exist avenues for gas transport. In situ, most coal deposits are water saturated and require reduction of hydraulic pressure to liberate the gas (Gray, 2003; Twombly et al., 2004). Once this pressure is removed Darcy’s Law takes effect with the gas desorbing from the coal surfaces, diffusing through the matrix via micropores until it can flow through microstructures and macrostructures towards the low pressure area created by the well (Gamson et al., 1996; McElhiney et al., 1993). Generally there are two scales of permeability present in coal, a macroscopic system composed of regular, persistent fractures and a microscopic system consisting of pores, cavities and the remains of original plant material. The degree to which these two systems connect and combine governs the flow rate and the quantity of gas that can be obtained.

The natural fracture system, known as cleats, present in coal are believed to have been formed by the interdependent influences of desiccation, lithification, coalification and paleotectonic stress (Close, 1993). As cleats provide the principal permeability pathway for the flow of gas and water throughout the coal, an understanding of their orientation, spacing, size, aperture width, connectivity and mineralization would greatly enhance the strength of gas field predictive models (Clarkson and Bustin, 1997; Close, 1993; Faraj et al., 1996; Laubach et al., 1998; Law, 1993). The cleat system generally occurs as an orthogonal set of fractures that is essentially perpendicular to bedding planes. The primary set, known as the face cleat, is the more dominant and continuous set while the secondary set, the butt cleat, is the more discontinuous set tending to terminate at intersections with the longer face cleats (Close, 1993; Laubach et al., 1998; Law, 1993; Pattison et al., 1996). Due to the persistent nature of the face cleats, there can exist significant face and butt cleat permeability anisotropy within coal reservoir with the greater permeability, suggested to be possibly as much as 3 - 10 times, parallel to the face cleat direction (Close, 1993; Laubach et al., 1998;

Law, 1993; Pashin et al., 1999). This obviously needs to be taken into account when determining well spacing and placement.

Face and butt cleats extend parallel to the maximum and minimum in situ stress directions respectively and hence can identify principal stress directions at the time of cleat formation (Li et al., 2004; Pashin et al., 1999). Uniformity of cleat orientations over wide areas containing relatively flat-laying, undeformed rocks is common (Close, 1993; Laubach et al., 1998). However, face and butt cleats are also known to strike essentially perpendicular and parallel to structures such as fold axes and faults (Close, 1993). So even though a regional scale orientation pattern may exist, caution must be exercised as abrupt variations, particularly at the local scale around deformation features, can impede or channelize flow through the cleat system (Laubach et al., 1998; Pattison et al., 1996). The coals of the Waikato possess a defined cleat system (St George, 1997) that is approximately parallel to regional bedding strike, with the exception of areas in the vicinity of faults, where cleat frequency increases and orientation is highly variable. They are thought to be tectonic in origin and the principal permeability direction is considered to run NE-SW (Cameron, 1995; Moon and Roy, 2004).

Cleat spacing in subbituminous coals have been reported as 0.01 - >10 cm in the Powder River Basin, USA (Flores, 2004), 7.6 - 12.7 cm in the Wyodak-Anderson coal, USA (Flores, 2004), 0.5 cm in Yima, China (Su et al., 2001), 0.29 - 0.5 cm in Kushiro, Japan (Li et al., 2004) and 1 - 4 cm for the Huntly coalfield (Mares and Moore, 2008b). Cleat size can vary from microscopic to the entire thickness of a seam and as with spacing can be affected by changes in ash content, bed thickness and lithotype (Close, 1993; Gamson et al., 1993; Su et al., 2001). Collecting meaningful aperture width data is very difficult to achieve under natural or replicated natural conditions. However, data on non-stressed coals as a function of lithotype is still more informative than no data at all (Close, 1993; Harpalani and Chen, 1995; Laubach et al., 1998). Measurements of aperture width, obtained using SEM and light microscopy, include 0.004-0.006 mm (Karacan and Okandan, 2000), 0.001 - 8 mm (Su et al., 2001), 0.01 - 0.3 mm (Close, 1993) and 0.1 - 2 mm (Gamson et al., 1996), while estimates of aperture width under in situ confining pressure vary from 0.1 to 100 nm (Harpalani and Chen, 1995).

A key component of cleat permeability is connectivity. The cleats must join to allow flow of gas and water and must also be open in situ, not held closed by effective stress (Close, 1993; Gamson et al., 1993). Secondary mineralization in the form of authigenic minerals such as calcite, quartz and clays, or organic material and resin, may be present in cleat apertures. Mineralization of cleats hinders the flow of gas and water and has been found to negatively influence the producibility of gas from coal (Close, 1993; Faraj et al., 1996; Laubach et al., 1998; Pashin et al., 1999). Law (1993) suggests that high rank coals commonly have mineral filled cleats and hence that their effective permeability may be less than low ranked coals with a wider cleat spacing.

The microstructural features with an influence on permeability include pores, microfractures, microcavities and phyteral porosity, formed by the remnants of original plant material (Clarkson and Bustin, 1997; Gamson et al., 1996). It has been shown that the size, continuity, connectivity and secondary mineral infill of these microfeatures have a significant contribution to overall permeability (Gamson et al., 1996). The nature of the pores, their size, concentration and surface area, is affected by rank and maceral composition (Crosdale et al., 1998; Lamberson and Bustin, 1993; Levine, 1993), while the other microstructures have been found to be controlled by coal type (Clarkson and Bustin, 1997; Gamson et al., 1996).

Microfractures were found to be common in bright coal lithotypes, typically forming a dense orthogonal network of fractures between the cleats. These in turn were found to be linked by smaller, less continuous, conchoidal fractures and striae. Microstructure in dull lithotypes is dominated by phyteral porosity and microcavities (Clarkson and Bustin, 1997; Gamson et al., 1996; 1993). Phyteral pores, associated with wood fibres, are cylindrical features that tend to occur in sheet like layers parallel to bedding. Microcavities are generally smaller than the other microstructures and vary in shape from small angular pores in between maceral fragments to complex, contorted pores between fibrous clay particles (Gamson et al., 1993). Detailed SEM imaging of phyteral porosity in a Turkish coal showed that the pores were connected to each other with microfractures less than 1 μm in aperture. This feature is promising in terms of gas transport and storage by increasing the accessibility of storage regions (Karacan and Okandan, 2001).

It was suggested by Gamson et al. (1996) that microstructures play a rate-limiting role between diffusion at the micropore level and flow at the cleat level as evidenced by the various microstructures and the different sorption behaviours of bright and dull coals. Differences in diffusivity of coals have important implications for gas drainage. Considering this, higher permeability may not necessarily offer higher gas flow rates if diffusivity is low, and low rank coals that possess low gas contents, because of low storage capacity, may offer better gas flow rates than some higher rank coals.

2.4 ENHANCED COAL BED METHANE (ECBM) AND CO2 SEQUESTRATION

It has been long recognised that coal can absorb greater volumes of CO_2 than CH_4, and the volumetric ratio of 2:1 has been widely reported for sub-critical CO_2 partial pressures (Cui et al., 2004; Gentzis, 2000; Krooss et al., 2002; Rodrigues and de Sousa, 2002). With the growing interest in low rank coal deposits for both CBM and CO_2 sequestration, evidence has emerged that this ratio can vary greatly in lignites and subbituminous coals. Published results where both vitrinite reflectance and CO_2:CH_4 ratios have been reported (Busch et al., 2003; Mares et al., 2008b; Mastalerz et al., 2004; Rodrigues and de Sousa, 2002; Saghafi et al., 2007) have been plotted in Figure 2.1. Other studies (Bustin, 2002; Stanton et al., 2001a; Stanton et al., 2001b) suggest ratios for low-rank coals of 10:1; Burress (2003) found ratios in subbituminous coals ranging from 7.4 to 10:1 and a ratio for lignite of 13.3:1, while Gluskoter et al. (2002) report that low-rank coals can hold 6 to 18 times more CO_2 than CH_4. These results clearly demonstrate that low-rank coals, particularly subbituminous coal, have good potential for CO_2 sequestration.

For the Waikato coalfield Mares et al. (2008b) found that CO_2:CH_4 ratios (daf) at 4 MPa range from 5.7 to 8.6, with the average being 6.7:1. That is, the coal can theoretically hold 6.7 times more CO_2 than CH_4 by volume, making the coal seams of the Huntly coalfield an attractive prospect for potential ECBM and CO_2 sequestration (Mares et al., 2008b; Zarrouk and Moore, 2008). This does not mean that all of the CH_4 can be removed and replaced with CO_2 in situ or that the CO_2 can be sequestered at maximum capacity (Bromhal et al., 2005). For instance, in an ECBM laboratory experiment Mazumder and Wolf (2008) found that for dry coals the sweep efficiency of CO_2 on CH_4 ranges from 60 to 90% of the CH_4 initially in place. It must also be noted that some of the injected CO_2 will dissolve into the immobile reservoir water under the high injection pressures. This is an exothermic (heat of solution) process that releases heat into the coal in the proximity of the wellbore.

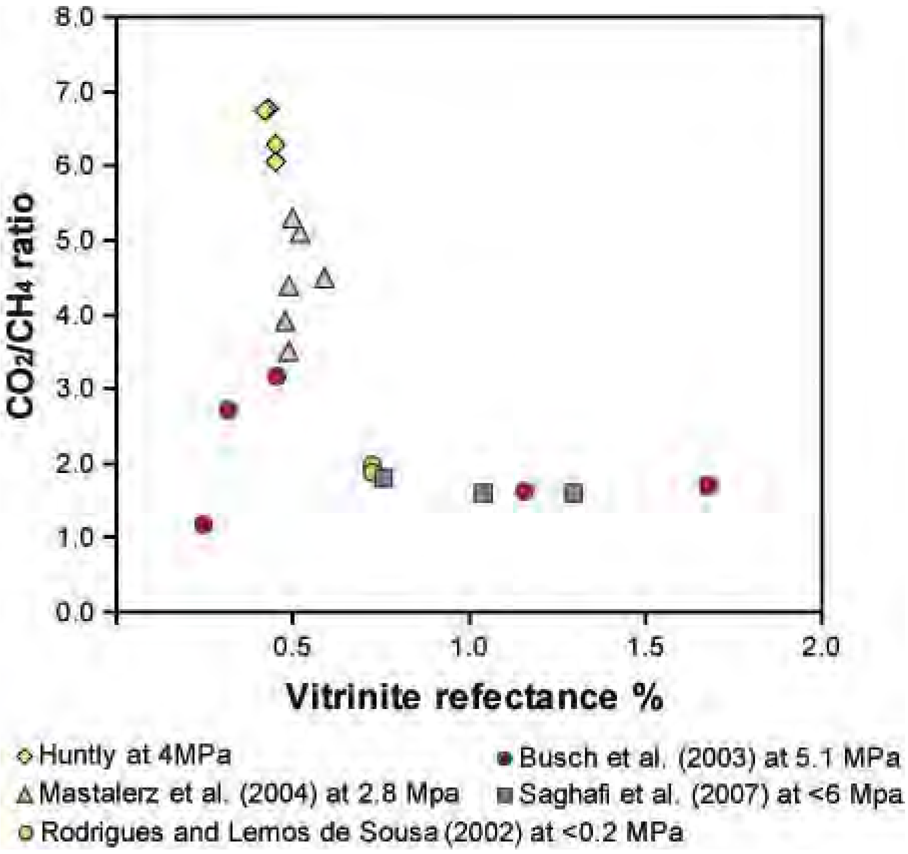


Figure 2.1. Ratio of carbon dioxide to methane adsorption versus rank. The Huntly data and that from Saghafi et al. (2007) are reported as R_{max}, while all other data reported for random vitrinite reflectance (Mares et al., 2008b).

While the replacement of CH_4 by CO_2 may sound simple, this is not the case. As coal actually adsorbs the solvents into its molecular structure (Yee et al., 1993) adsorption and desorption of adsorptive gases, such as CO_2 and CH_4, cause volumetric changes in the coal matrix (Harpalani and Chen, 1992; 1995; Harpalani and Schraufnagel, 1990; Harpalani et al., 2006). During the production phase of a CBM project depressurization of the reservoir and desorption of gas leads to the coal matrix shrinking, resulting in opening of the cleats and hence an increase in permeability (Harpalani and Chen, 1992; 1995; Harpalani and Schraufnagel, 1990). This has been confirmed by field projects such as the Fruitland Formation in the San Juan Basin where absolute permeability increased with continued production (Mavor and Vaughn, 1998). Swelling of coal due to sorption of gases and liquids is a well reported phenomenon (Bustin et al., 2008; Cody et al., 1988; Day et al., 2008a; Harpalani et al., 2006; Karacan and Mitchell, 2003; Kelemen et al., 2006; Levine, 1996; Mazumder and Wolf, 2008; Mitra and Harpalani, 2007; Pone et al., 2008; Zarebska and Ceglarska-Stefanska, 2008). Unfortunately, swelling of coal in a confined pressure environment results in closure of the cleats and a decrease in permeability.

Siriwardane et al. (2008) found while the permeability of fractured coal samples did not change with time when exposed to an inert gas (argon), exposure to CO_2 resulted in a permeability reduction of as large as 70% of the original size for larger fractures and up to 90% for smaller fractures. Permeability of the smaller fractures was found to be similar to the matrix permeability leading to the authors hypothesising that these fractures would be completely closed in situ. From numerical modelling and adsorption isotherm data Deng et al. (2006) concluded that in a worst case scenario CO_2 injection would reduce permeability to 1/10 of its initial value while hydrogen sulphide (H_2S) would reduce permeability to 1/100. In contrast to this, injection of N_2 resulted in a 10 times enhancement of permeability. Lin et al. (2007) suggested that by including a small amount of N_2 in the injected gas (CO_2), 10 – 20% by mole, permeability could be significantly preserved. N_2 is the main gas component in air and thus is also the major component in the flue gases from which CO_2 is separated. As such, flue gas injection scenarios are also now being investigated by many researchers (Deng et al., 2006; Jessen et al., 2007; Law et al., 2003b; Mazumder et al., 2006; Zarrouk and Moore, 2008).

2.5 ECBM FIELD TRIALS

2.5.1 U.S.A.

The largest and longest running CO_2 ECBM pilot is in the Allison Unit of the San Juan Basin, operated by Burlington Resources, with four injectors and 16 production wells. In the targeted area, the medium volatile bituminous coals of the Fruitland coal seam are 13 m thick, had an estimated initial absolute permeability of 100 md and are located at a depth of 945 m. Approximately 370,000 tons of CO_2 were continuously injected between 1995 and 2001 with constant bottom hole pressures (2400 - 2500 psi) and with injection rates allowed to vary (330 - 660 Mcf/day ~ 17 - 33 ton/day).

Initially during the injection period a reduction in injectivity of about 60% was observed. Well testing indicated that the coal permeability in the near well area had decreased to approximately 1 md, a reduction of up to two orders of magnitude, with effects becoming less severe to a maximum distance of 300 m. Following this initial decline there was an unexpected rebound in injectivity thought to be a result of the continual decrease in overall reservoir pressure (production volumes were much greater than injection volumes) enabling the CO_2 adsorbed near the well to desorb and migrate further into the reservoir. This would result in matrix shrinkage and permeability increase similar to that seen during primary CH_4 depletion.

The project showed significantly improved CH_4 recovery, with recovery increased from 77% to 95% of original gas in place within the pilot area. It was estimated that one volume of CH_4 was recovered per four volumes of CO_2 injected. Initial breakthrough was seen in July 1996 (17 months after commencement) however over the following 3.5 years the CO_2 concentration only increased from 5% (pre-injection level) to 9.5%. Of the injected CO_2, 300,000 ton were stored with 70,000 ton being re-produced. This CO_2 was reinjected (Kuuskraa, 2005; Oudinot et al., 2007; Reeves, 2005).

The Tiffany Unit N_2 ECBM pilot, operated by BP America, in also located within the San Juan Basin and is of considerable scale. The coals are again medium volatile bituminous rank, at 914 m depth and 14 m thickness however, in contrast to the Allison Unit the initial absolute permeability is only around 1 md. The study area consisted of 34 CBM production wells and 12 N_2 injectors with spacing between injectors and producers similar to that used in the Allison Unit pilot. N_2 injection commenced in January 1998 and was injected at rates of 3000 – 3300 Mcf/day (~97 – 107 ton/day), with injection pressures of 1500 - 1700 psi, during the winter months until January 2002.

The N_2 showed superior injectivity thought to be a result of higher near well permeability, ~10 md under injection conditions, as well as a lower viscosity for N_2. As expected N_2 breakthrough occurred very quickly in mid- 1998. The response to injection in the production wells was rapid and dramatic. During the initial injection period the total CH_4 production rate for the field increased by over a factor of 5. It was estimated that one volume of CH_4 was recovered for every 0.4 volumes of injected N_2 (Oudinot et al., 2007; Reeves et al., 2004).

2.5.2 Canada

Starting in the late 1990’s the Alberta Research Council conducted a series of single well micro-pilot tests in two stimulated wells located near the towns of Fenn and Big Valley, Alberta. The wells targeted the 4 m high volatile bituminous upper Mannville seam in the Medicine River formation at depths around 1250 m. In the first well over 91,500 m^3 of CO_2 vapour was injected in 12 cycles. Although the absolutely permeability decreased, from around 3.5 md to 0.99 md, injectivity actually increased possibly a result of coal weakening. Later on, 83,500 m^3 of flue gas (84.2% N_2, 12.4% CO_2, 2.1% Ar and 1.2% CO) was injected over six days at rates between 11 and 24 m^3/min (roughly 19 - 42 ton/day) at a pressure of 12,400 kPa (g). Flue gas injection substantially increased the absolute permeability from the post-CO_2 injection level.

In the second well N_2 injectivity tests, also resulting in greater permeability, were conducted prior to injecting 75,483 m^3 of a 53% - 47% mix of N_2 and CO_2 with average injection rates of 10.18 m^3/min for N_2 and 8.94 m^3/min for CO_2. In both wells CO_2 surprisingly showed greater injectivity than other gases while flue gas injectivity was similar to that of N_2. It is believed the alternating sequence of injection-falloff periods during CO_2 injection improved injectivity. It was generally thought that CO_2 would displace all of the hydrocarbons away from the injection well however it was found that 20% of hydrocarbons remained in the CO_2 contact area (Mavor et al., 2004).

Of particular interest to New Zealand is a trial in the Red Deer Area, Alberta, Canada which will inject into the 5 m thick Ardley coal. The Ardley coal has characteristics similar to the Waikato coalfield being a Tertiary coal of subbituminous B to high volatile bituminous C in rank (vitrinite reflectance 0.47%) at a depth of 300 m. Permeability is thought to range from 1 - 10 md. Future plans for this site are to trial the enhancement of methanogenesis (Connell, 2008a; Deng et al., 2008; Kuuskraa, 2005; Law and Gunter, 2003).

2.5.3 Poland

The RECOPOL project in the Upper Silesian Basin, Poland, began in the summer of 2003. An existing CBM well was cleaned up and a new injector well was drilled and completed 150 m away. Three seams of between 1.3 and 3.3 m in thickness were targeted at a depth of around 1100 m. The Carboniferous coals are high volatile bituminous in rank (Pagnier et al., 2005) and permeability has been found to be relatively low to moderate 0.5-5 mD (van Bergen et al., 2005).

760 tonne of liquid CO_2 was injected between August 2004 and the end of June 2005 with an average injection rate of 12-15 tonne/day and well head pressures between 80-120 bar (Kretzschmar, 2005). Fall-off tests indicated that permeability was reduced significantly by a factor of 10-100. This decrease is thought to be the result of coal matrix swelling as a response to CO_2 adsorption (van Wageningen and Tejera-Cuesta, 2005). In November 2004 there was a slow rise in CO_2 at the production well with isotopic evidence of injected CO_2 from December 2004 (Kotarba et al., 2005). About 10% of the injected CO_2 was produced from the production well during the trial period, meaning about 692 tonne have been successfully stored by the coal, with methane production rates being increased significantly in comparison to baseline (pre CO_2 injection) production (van Bergen et al., 2008).

2.5.4 Japan

The JCOP project commenced in 2002 in the Yuubari area of the Ishikari coal field, Hokkaido. The location was selected as the high volatile bituminous coal seams in the area are gassy and permeable. A pilot project of one injector and one deviated producer were drilled in 2004 with a horizontal separation of about 65m in the coal seam. The wells were perforated in the lower of three major coal seams between 890 and 895 m depth (Shi et al., 2008). Initial reservoir conditions were: permeability 0.9 - 1.6 md, reservoir pressure 10 MPa and temperature 30 ºC (Ohga et al., 2005).

A preliminary ECBM trial in November 2004 injected 35.7 tonne of CO_2 at an average of 2.3 tonne/day. In 2005 three times as much CO_2 was injected at an average rate of 2.75 tonne/day. As these injection rates were much lower than originally estimated a N_2 flooding trial was conducted in 2006. The N_2 flooding improved the CO_2 injection rate but only temporarily as it quickly reduced to its original level. There was clear evidence that CO_2/N_2 injection resulted in an increase in gas production rates with little effect on water production (Shi et al., 2008).

2.5.5 China

A single well micro-pilot test was performed in anthracitic coals of the South Quinshui basin, Shanxi Province, China. The coal seam is about 5 - 6 m thick at a depth of 472 m with effective permeability of the coal to gas of 1.8 mD prior to CO_2 injection. The trial commenced in April 2004 with a total of 192 tonne of liquid CO_2 injected in 13 slugs at pressure of 8 MPa. Injectivity decreased initially but stabilized during the trial period (Wong et al., 2006).

2.5.6 Other

Several other trials are in the planning/preliminary phase in Canada, U.S.A. and Australia as well as further work planned on the pilots in China and Japan.

2.6 ECBM ECONOMICS

As field trials to date have been designed to determine the technical rather than the economic feasibility of CO_2 sequestration in unminable coal seams, Robertson (2008) conducted an economic analysis of sequestering both flue gas and separated CO_2 emissions from Wyodak PC power plant into the Wyodak-Anderson subbituminous coal zone in the Powder River Basin. The scenarios were based on a 5-spot pattern with 320 acre (1.3 km^2) well spacing, a 1:1 ratio of injection to production wells and the requirement of a 80.5 km pipeline from source to site. It was found that injecting CO_2 in this location was uneconomic and, as the major cost driver was the separating of CO_2 from the flue gas, was unlikely to become economic without an incentive scheme. The injection of flue gas may be economic however as it does not sequester CO_2 in large quantities it should only be considered as a CBM enhancement method.

Deng et al. (2006) also compared the economics of flue gas and CO_2-ECBM using data based on the Mannville coal in western Canada. For this scenario a 5-spot pattern was used with a 320 acre well spacing. The coal seam is 9 m thick at a depth of 1200 m. Economically flue gas was again favoured of pure CO_2 injection costs although acid gas (not produced in New Zealand) was preferred over flue gas. Closer to home, Sander and Allison (2008) modelled several ratio combinations of injector : production wells for injection of pure CO_2

into low rank coals typical of Victoria (and New Zealand). The study found that with low gas prices and no carbon storage incentives CO_2-ECBM has very limited economic potential.

2.7 METHANOGENESIS

Following CBM reservoir depletion and CO_2 injection (ECBM), current research is looking into the regeneration of coalbed methane using methanogens. Methanogenic consortia are composed of anaerobic archaea and bacteria which convert organic substrates (including hydrogen, CO_2, acetate and formate see equations 2.1 and 2.2) into methane. With the addition of CO_2 to the coal beds, it is assumed that the indigenous methanogenic consortium or injected consortium should be able to convert the CO_2 to CH_4 (Budwill et al., 2003).

Some researchers have identified and/or sequenced methanogens collected from both coal (Klein et al., 2008; Li et al., 2008) and coal formation waters (Green et al., 2008; Klein et al., 2008; McIntosh et al., 2008; Shimizu et al., 2007; Strapoc et al., 2008b; Thielemann et al., 2004) with Ulrich and Bower (2008) confirming current, in situ active methanogenesis in the Powder River Basin, U.S.A. Experiments culturing of both indigenous and foreign methanogenic consortia have successfully produced CH_4 under laboratory conditions, both with and without nutrient enhancement (Budwill et al., 2005; Chou et al., 2008; Green et al., 2008; Harris et al., 2008; Ulrich and Bower, 2008), with rate limiting factors found to be temperature, pH, pressure and surface area (Budwill et al., 2005; Green et al., 2008; Harris et al., 2008). It has also been suggested that formation water is required for the conversion to take place as methanogens derive from the water nearly all the hydrogen required to produce methane (Budwill, 2003; Luca Technologies, 2004). As methanogens have been reported to be around 0.2 – 6.0 µm in diameter (Gilcrease and Shurr, 2007; Strapoc et al., 2008b), larger than many coal pores, it has been proposed that microbial access maybe limited to cleat surfaces and that accessibility may contribute to the in-seam variability identified in gas content (Strapoc et al., 2008a).

Field trials for in situ stimulation of methanogenesis have commenced, with Luca Technologies recently completing a field trial in the Powder River Basin. While the details of the trial are not yet available, the company reports that it “has yielded encouraging results” (Gilcrease and Shurr, 2007).

3.0 DATA: RESERVOIR PROPERTIES

In preliminary models, such as those presented in this study, many parameters are unknown and must be estimated. Where available, data has been utilised from previously published papers (Crosdale et al., 2008; Mares and Moore, 2008a; 2008b; Mares et al., 2008a; 2008b; Zarrouk and Moore, 2007; 2008), a thesis (Mares, in prep) and also from some internal reports. No new analyses have been conducted as part of this study. The models presented were designed to be generic, i.e. square grids with layers of uniform thicknesses, yet realistic of field development design as a first assessment of 3 different locations within the Waikato coalfields (Figure 1.3). Locations were selected to represent varied reservoir properties and settings with Ruawaro being high gas content, low-moderate permeability and medium depth, Mangapiko being low gas content, high permeability and deeper than Ruawaro and Ohinewai being low gas content, low-moderate permeability and shallow in coal depth.

3.1 GEOLOGY

A general stratigraphic column for the Waikato coalfields in the northern area, where coal bed methane (CBM) exploration has been concentrated to date, was presented previously in Figure 1.2 (Mares and Moore, 2008b). Not all units are present in all locations and thickness of units also varies between locations. In the interest of limiting the number of blocks used in the model, similar units have been grouped into single model layers (Table 3.1 and Table 3.2). For the Ohinewai scenario (Table 3.3) where fewer units have been identified thicker units have been split into several layers. To date the Renown coal seam has been identified as the major target for CBM production hence for the Ruawaro and Mangapiko scenarios the Kupakupa seam has been excluded. As the Renown and Kupakupa seams at the Ohinewai location were split only by 0.5 m, both seams have been modelled with production and injection located in the lower part of the Kupakupa seam.

A relatively high geothermal gradient has been reported for the area, between 52 – 55 °C with a heat flux of more than 100 mW/m^2, probably a result of the close proximity to the Taupo Volcanic Zone (Zarrouk and Moore, 2007). A reservoir temperature of 40 ºC has been measured at 440 m depth with water chemistry indicating that the reservoir water has originated from the deep basement with an equilibrium temperature of around 90 ºC (Zarrouk and Moore, 2007). Using this gradient, temperature profiles have been generated for each location from which profiles of hydrostatic pressure for each layer could also be calculated (Figure 3.1 to Figure 3.3) using:

$$P = \rho . g . h \tag{3.1}$$

Where:

P	pressure in Pa
ρ	density of water at the given depth and temperature in kg/m^3
g	gravity = 9.81 m/s^2
h	depth in m

3.1.1 Ruawaro

Table 3.1. Reservoir properties for model layers in the Ruawaro scenario.

Model Unit	Thick (m)	Depth to (m)	Unit	Mid point (m)	Temperature (°C)	Pressure (Pa)
1	30.0	30.0	Tauranga	15.0	17.0	146963
2	149.4	179.4	Whaingaroa Siltstone	104.7	20.3	1025152
3	60.0	239.4	Glen Massey Sandstone	209.4	25.8	2047624
4	108.9	348.3	Dunphail to Mangakotuku Siltstone	293.9	30.3	2869892
5	23.7	372.0	Pukemiro Sandstone	360.2	33.9	3513484
6	10.0	382.0	Glen Afton Claystone	377.0	34.8	3676724
7	25.7	407.7	Waikato Coal Measures	394.9	35.7	3849581
8	6.0	413.7	Renown Coal	410.7	36.6	4002829
9	12.8	426.5	Waikato Coal Measures	420.1	37.1	4093709

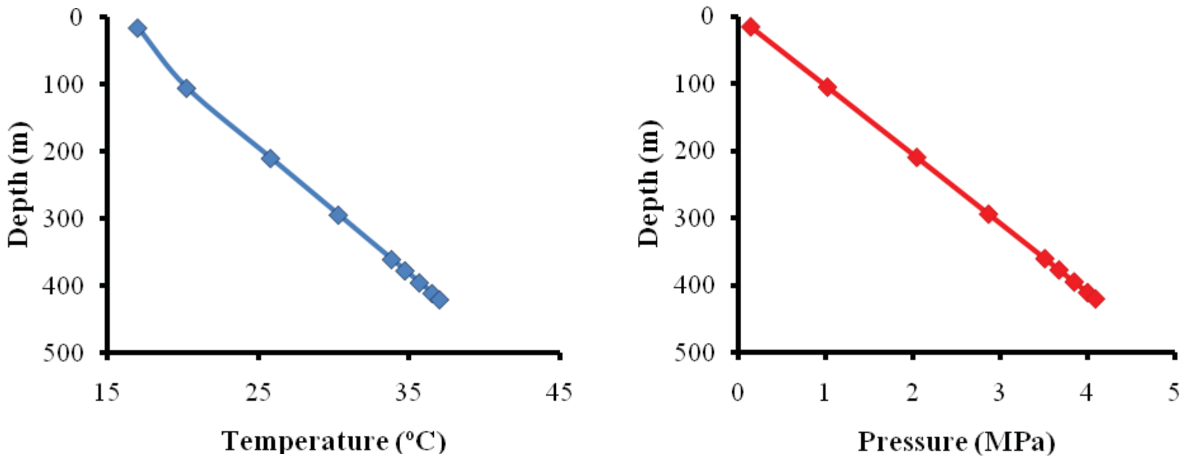


Figure 3.1. Temperature and pressure depth profiles for the Ruawaro location.

3.1.2 Mangapiko

Table 3.2. Reservoir properties for model layers in the Mangapiko scenario.

Model Unit	Thick (m)	Depth to (m)	Unit	Mid point (m)	Temperature (°C)	Pressure (Pa)
1	11.0	11.0	Tauranga	5.5	17.0	53886
2	129.0	140.0	Whaingaroa Siltstone	75.5	18.7	739483
3	120.0	260.0	Glen Massey Sandstone	200.0	25.3	1955961
4	139.5	399.5	Dunphail to Mangakotuku Siltstone	329.8	32.3	3218330
5	26.0	425.5	Pukemiro Sandstone	412.5	36.7	4019938
6	12.0	437.5	Glen Afton Claystone	431.5	37.7	4203557
7	44.3	481.8	Waikato Coal Measures	459.7	39.2	4475276
8	5.6	487.4	Renown Coal	484.6	40.5	4715847
9	24.0	511.4	Waikato Coal Measures	499.4	41.3	4858368

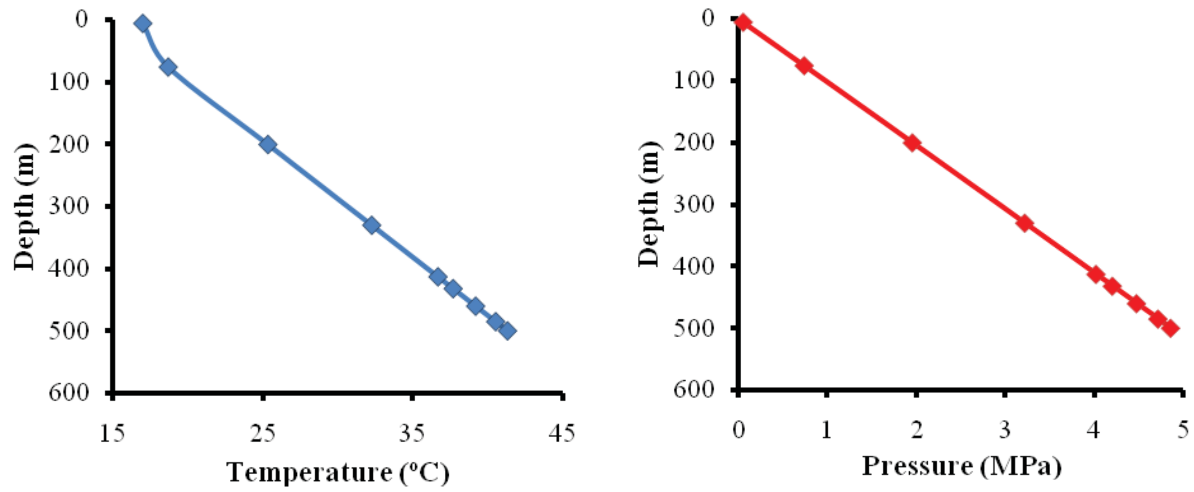


Figure 3.2. Temperature and pressure depth profiles for the Mangapiko location.

3.1.3 Ohinewai

Table 3.3. Reservoir properties for model layers in the Ohinewai scenario.

Model Unit	Thick (m)	Depth to (m)	Unit	Mid point (m)	Temperature (°C)	Pressure (Pa)
1	50.0	50.0	Tauranga	25.0	17.0	244939
2	60.0	110.0	Tauranga	80.0	18.9	783676
3	36.1	146.1	Waikato Coal Measures	128.1	21.5	1253457
4	6.7	152.8	Renown Coal	149.5	22.6	1462574
5	7.1	159.9	Kupakupa Coal	156.4	23.0	1529959
6	8.0	167.9	Kupakupa Coal	163.9	23.4	1603685
7	3.7	171.6	Waikato Coal Measures	169.8	23.7	1660805
8	200.0	371.6	Basement	271.6	29.2	2653339

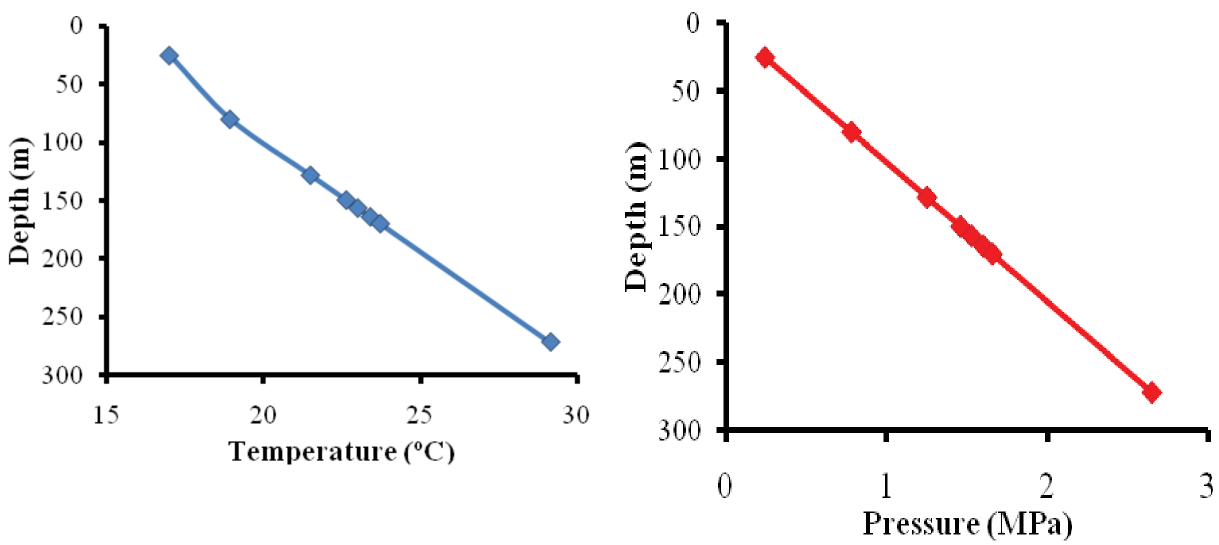


Figure 3.3. Temperature and pressure depth profiles for the Ohinewai location.

3.2 GAS CONTENT AND GAS COMPOSITION

Total gas content of coal collected from the Huntly coalfield is widely available (Butland and Moore, 2008; Mares and Moore, 2008a; 2008b; Mares et al., 2008a; Moore and Butland, 2005; Twombly et al., 2004). Coal core, and any interburden material showing signs of gas, retrieved from drill holes was split into 0.5 m lengths and quickly sealed in gas desorption canisters (Moore et al., 2004). Once sealed, the canisters were maintained at reservoir temperature for the period of the gas desorption analyses using a water bath and later a temperature controlled room. Gas volume readings were initially taken every 15 minutes with the time interval between readings being increased as the desorbed volume of gas decreased (Barker et al., 2002; Moore and Butland, 2005; Moore et al., 2004) over a 10 day period. Residual gas was determined using methods outlined in Moore et al. (2004) and Moore and Butland (2005), while the lost gas correction and total gas volume were calculated using Barker et al. (2002) methodology. It is important to note that this method does not take free gas into consideration (Bodden and Ehrlich, 1998). Average total gas contents, on an as analysed basis, for the locations of interest are presented in Table 3.4.

During drilling gas was seen escaping from some areas of the Waikato Coal Measures (WCM) it was decided to include this in the models. It is acknowledged that in reality the gas is probably not consistently spread throughout the WCM, maybe just concentrated in the carbonaceous material in mudstones around the coal seams, and this may need to be adjusted in future modelling scenarios. Gas content for WCM material was only available for the Ruawaro location, so to generate gas contents for the WCM in other locations gas content was multiplied by the ratio for coal to WCM gas content from the Ruawaro location.

Table 3.4. Total gas contents for coal and coal measures units.

	Total Gas Content (as analysed m^3/tonne)
Ruawaro coal	2.53
Ruawaro WCM	0.71
Mangapiko 1 coal	0.94
Mangapiko 1 WCM	0.28
Ohinewai Renown coal	0.22
Ohinewai Kupakupa coal	0.18
Ohinewai WCM	0.28

Numerous gas composition results for the Huntly coalfield have also been published with CH_4 content always being greater than 90% and CO_2 generally composing <2% (Butland and Moore, 2008; Mares and Moore, 2008b; Moore and Twombly, 2006). Trace amounts of C_2H_4, C_2H_6 and H_2 have also been reported to occur (Butland and Moore, 2008). Gas composition used in the present study are presented in Table 3.5.

Table 3.5. Gas composition used in this study.

	Percentage
Methane	97.0
Carbon Dioxide	0.5
Nitrogen	2.4

3.3 GAS HOLDING CAPACITY

CH_4, CO_2 and N_2 adsorption isotherms for the Waikato coalfields have been published by Crosdale et al. (2008), Mares and Moore (2008b), Mares et al. (2008a; 2008b) and Zarrouk and Moore (2008) and were measured according to procedures outlined by Moore and Crosdale (2006) and Crosdale et al. (2008) at reservoir temperature. All gas adsorption analyses were conducted at the same laboratory (Energy Resources Consulting, Australia) under the same temperature (~32 °C) and equilibrium moisture (~20%) conditions. For CH_4 and N_2 gases nine pressure steps were used up to a maximum pressure of 8MPa while for CO_2 seven pressure steps were used to 5MPa. At each pressure step a fixed volume of gas was introduced and monitored to the nearest 1kPa until there was no change in pressure for a period of at least 1 hour. Equilibrium generally took around 2 - 4 hours to obtain. Adsorption isotherms for the gases were fit to the Langmuir equation assuming a mono-layer gas adsorption mechanism (Gregg and Sing, 1982) and results have been standardized to 20 °C and 1 atmosphere pressure (101.3 kPa).

CH_4 and CO_2 adsorption isotherms have been measured for coal from all 3 locations selected for this study with N_2 only being measured for the Ruawaro coal. A CH_4 adsorption isotherm sample for the WCM was also analysed from the Ruawaro drillhole. Where required, N_2 isotherms were generated using the ratio of the CH_4 to the N_2 isotherm at each pressure point from the Ruawaro isotherms. An adsorption isotherm for CO_2 for the WCM sample was generated in a similar manner using the ratio of CO_2 to CH_4 from the Ruawaro coal sample. Adsorption isotherms for H_2S gas are very rare and have not been conducted on New Zealand coals. Deng et al. (2006) presented adsorption isotherms for all four gases (CH_4, CO_2, N_2 and H_2S) on Canadian coals with the Ardley coal being of similar rank (R_o: 0.4 – 0.55%) to the Huntly coals (Figure 3.4). As such, H_2S adsorption isotherms for each location were generated using the ratio of the H_2S to the CO_2 adsorption isotherm from the Ardley coal sample (Figure 3.5).

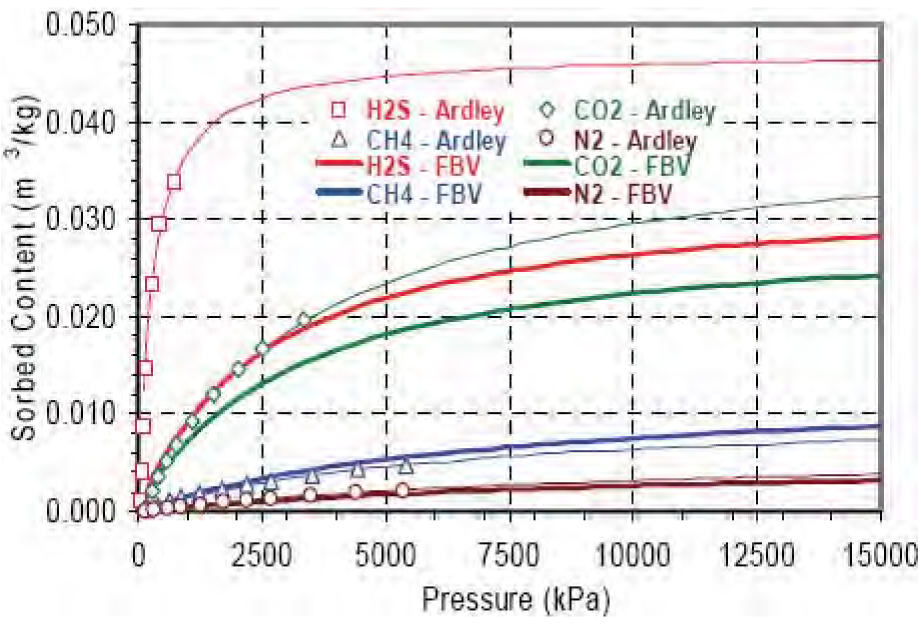
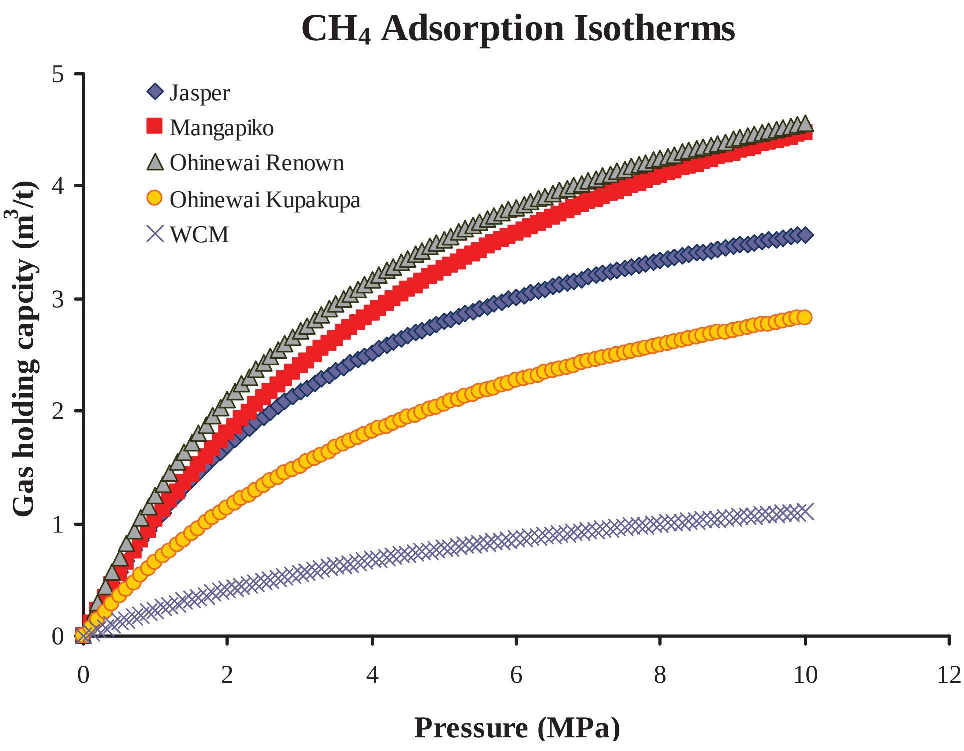


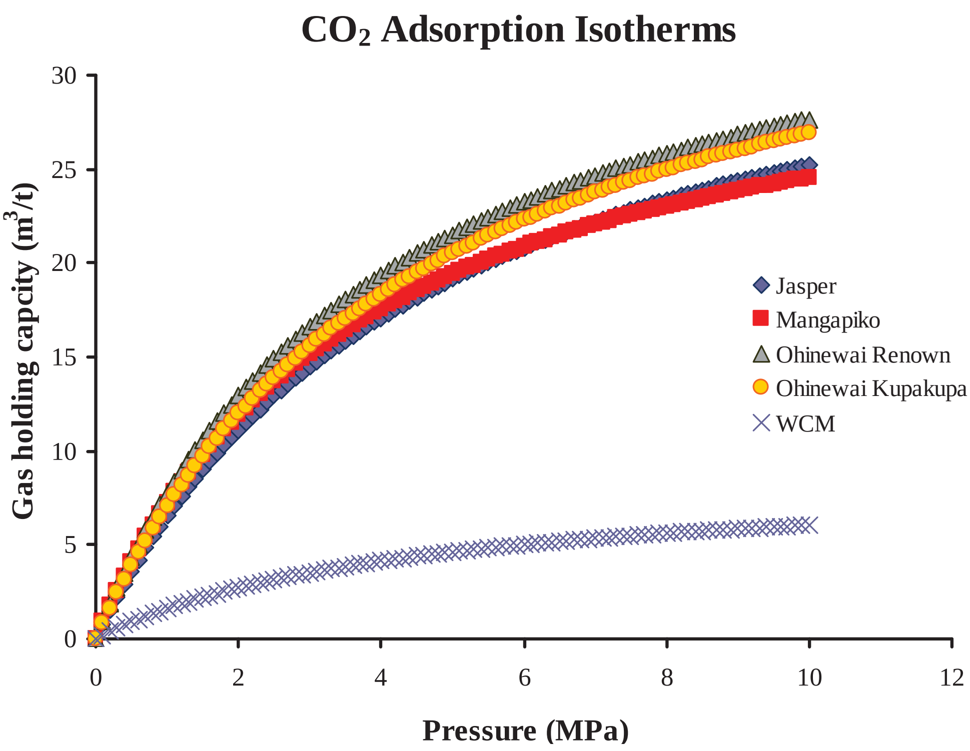
Figure 3.4. Gas adsorption isotherms for Canadian coals (Deng et al., 2006).

(A)



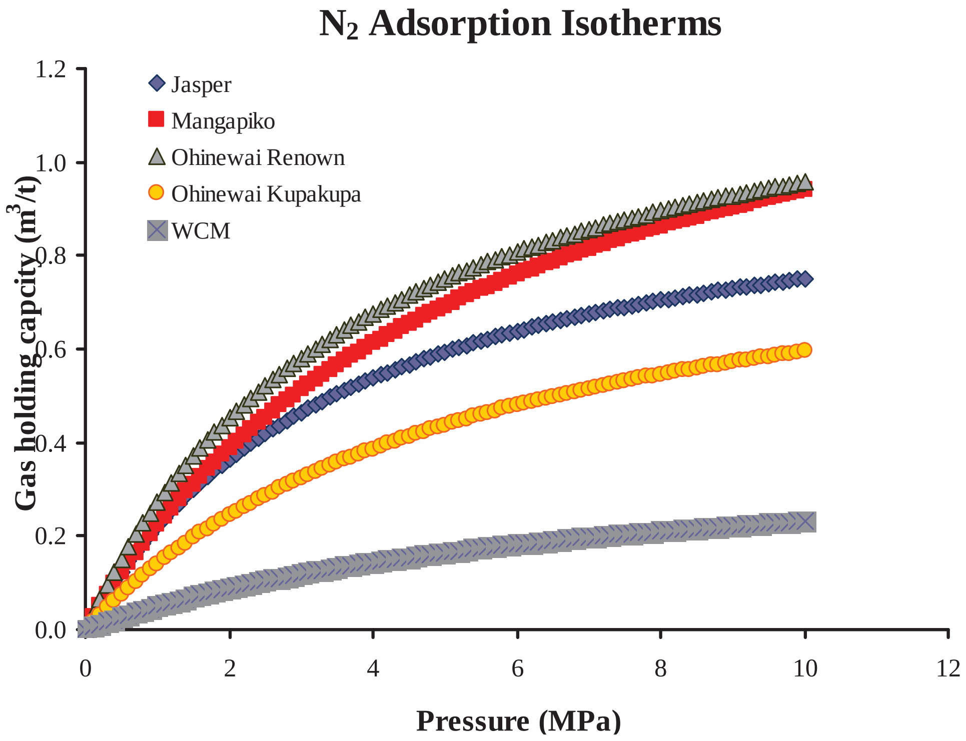
CH4 Adsorption Isotherms
Jasper
Mangapiko
Ohinewai Renown
Ohinewai Kupakupa
WCM
Gas holding capcity (m3/t)
Pressure (MPa)
0
1
2
3
4
5
0
2
4
6
8
10
12

(B)



CO2 Adsorption Isotherms
Jasper
Mangapiko
Ohinewai Renown
Ohinewai Kupakupa
WCM
Gas holding capcity (m3/t)
Pressure (MPa)
0
5
10
15
20
25
30
0
2
4
6
8
10
12

(C)



(D)

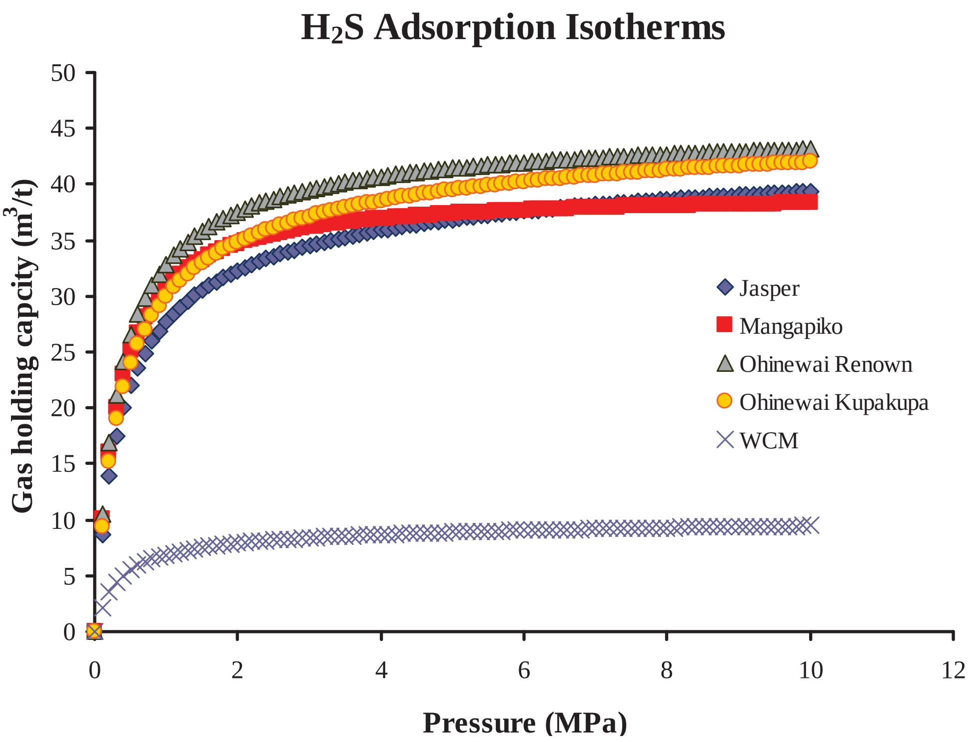


Figure 3.5. Gas adsorption isotherms for (A) CH_4, (B) CO_2, (C) N_2 and (D) H_2S. H_2S isotherms were proportioned from (Deng et al., 2006) and where necessary N_2 and CO_2 proportioned from Ruawaro as described in the text.

3.4 PERMEABILITY, POROSITY AND COMPRESSIBILITY

Published permeability data for coals in New Zealand are not common. However, Manhire and Hayton (2003) do report permabilities between 1 - 15 mD for coal seams of similar rank to the Huntly coals. These permeabilities are consistent with unpublished, confidential injection/fall off test results for the Huntly coal seams. The data used for this part of the study was taken from Zarrouk and Moore (2008).

Core samples from several exploration and appraisal wells in the Huntly coalfield were tested for stress dependent matrix permeability using a triaxial stress cell. The triaxial stress cell was used for measuring both the vertical and horizontal matrix permeabilities from several core samples. These core samples were collected immediately after leaving the desorption canisters where they were covered in plastic sealing tape, placed in a sealed container and stored at 4°C to prevent oxidation. Permeability measurements were taken at various confining stress levels that correspond to the actual coal depths. The tests were repeated using, CH_4 and CO_2 for each sample with the stress dependent permeability curves plotted in Figure 3.6. Further tests were conducted on additional coal samples for CH_4, CO_2 and N_2 (as reported by St George, 2008). However, these results were not made available till December 2008, and hence owing to time constraints, were not able to be included in the current modelling study.

The samples were tested for both vertical and horizontal matrix permeability using CH_4, CO_2 and N_2 and demonstrate relatively low permeability and high stress dependency. St George, (2008) concluded that: due to the high fractured nature of the coal, field permeability could well be much higher than measured laboratory values. This comment is in line with field permeability measurements from well testing. The pressure/stress dependency of the permeability however, will be of major significance to reservoir modelling.

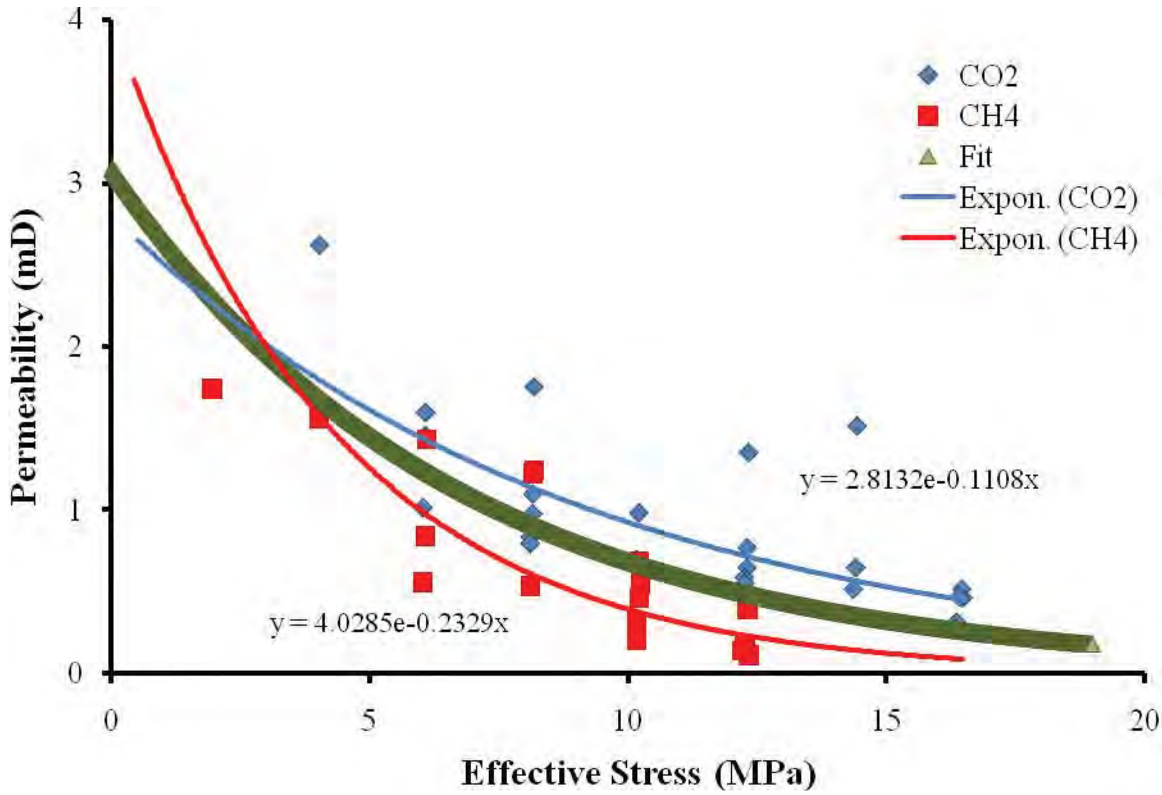


Figure 3.6. Stress dependent permeability for CH_4 and CO_2 with the exponential fit for both (Zarrouk and Moore, 2008).

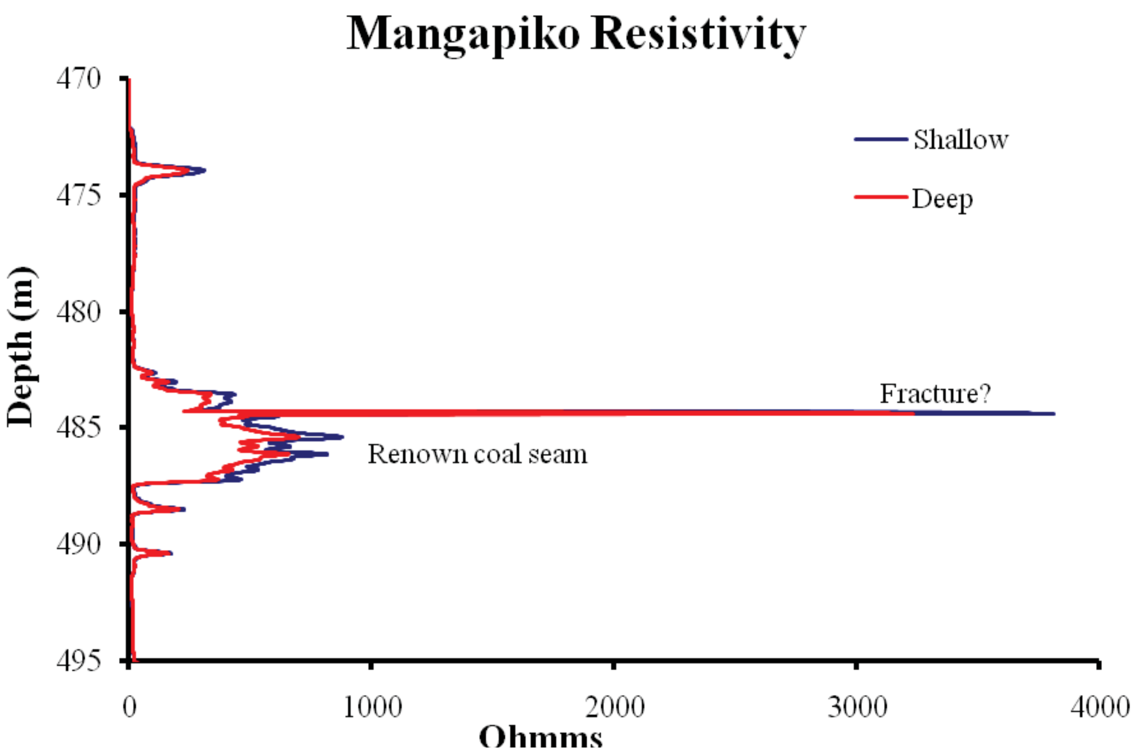
Unfortunately porosity and permeability data for geological units other than the coal seams are very limited. Before any trials go ahead permeability and porosity of the overlying units should be assessed to properly consider seal integrity. Some porosity work has been done on the Huntly coal (Mares et al., 2008b) using small angle scattering techniques however these analyses were conducted on dry coal samples. The study found that the majority of the porosity was in the micropore size range which is likely water saturated in reservoir conditions. As such a much lower value for coal porosity, 2%, has been used for this study (Zarrouk and Moore, 2008), which was based on measured storativity from interference testing.

The values used for the effective (flow) porosity and permeability of the different geological units in this study were based on experience and are presented in Table 3.6. It was decided to keep horizontal permeabilities isotropic and vertical permeability was set at one order of magnitude less than the horizontal permeability. That the coal is more permeable than the surrounding coal measures can be seen in the geophysical logs (Figure 3.7) where the shallow resistivity profile diverges from the deep resistivity profile.

Table 3.6. Estimated values for porosity and permeability used in this study.

	Porosity (%)	**Horizontal Permeability (mD)**
Tauranga	0.3	100
Whaingaroa Siltstone	0.01	0.005
Glen Massey Sandstone	0.2	50
Dunphail to Mangakotuku Siltstone	0.005	0.005
Pukemiro Sandstone	0.11	10
Glen Afton Claystone	0.001	0.001
Waikato Coal Measures	0.01	0.1
Renown Coal	0.02	4
Mangapiko Coal	0.01	30.5
Coal Fractures	0.3	1000
Waikato Coal Measures	0.01	0.1
Basement	0.01	0.001

(A)



(B)

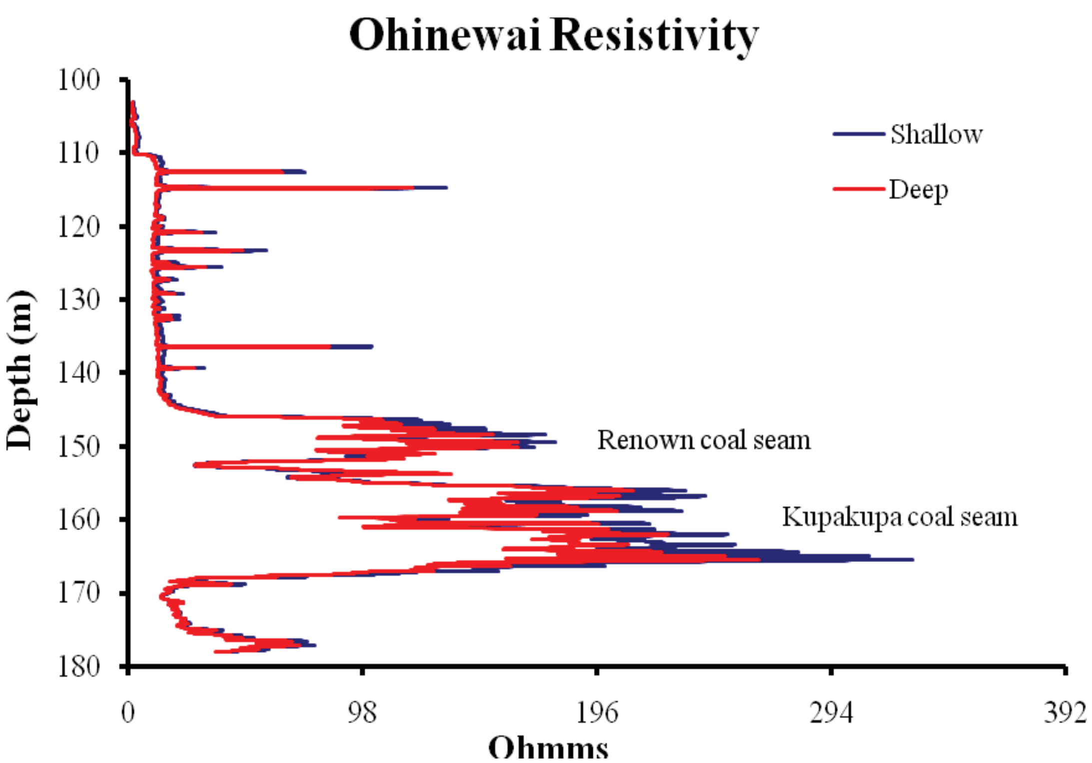


Figure 3.7. Down hole resistivity logs for (A) Mangapiko and (B) Ohinewai.

4.0 RESERVOIR MODELLING

4.1 MODEL PARAMETERS

A new equation of state for a mixture of water, CH_4, CO_2, N_2 and H_2S has been developed for three dimensional modelling of enhanced CBM reservoirs using the TOUGH2.2 reservoir simulator (Pruess et al., 1999). The new equation of state (ECBM) incorporated gas properties from the equations known as 'EWASG' (Battistelli et al., 1997) and 'EOS11' (Zarrouk, 2008). The new simulator has been trialled on several test problems and the model results have been compared with results from existing commercial packages (see Zarrouk, 2008). The simulator has also been used for preliminary ECBM models for the Huntly coalfield, the results of which have been published by Zarrouk and Moore (2007; 2008).

The adsorption of CH_4, CO_2, N_2 and H_2S in a coal seam is considered in TOUGH2.2 through adding a pressure (gas partial pressure) dependent term to the mass accumulation term for CH_4, CO_2, N_2 and H_2S. Thus the equation becomes:

$$M_{\beta}^{(\kappa)} = \phi \sum_{\beta=1}^{NPH} S_{\beta} \rho_{\beta} X_{\beta}^{(\kappa)} + (1-\phi)\rho_{coal} . f^{(\kappa)} \tag{4.1}$$

where:

$M_{\beta}^{(\kappa)}$	Mass accumulation term of component κ in phase β.
ϕ	Porosity
NPH	Number of phases (1 liquid and 2 gas/vapour)
S_{β}	Saturation of phase β
ρ_{β}	Density of phase β
$X_{\beta}^{(\kappa)}$	Mass fraction of component κ in phase β
ρ_{coal}	Density of coal
$f^{(\kappa)}$	The mass of component (κ) adsorbed per mass of solid given by:

$$f^{(\kappa)} = \left[1-\left(m_c + w_c\right)\right] \frac{V_L^{(i)}.b^{(i)}.y^{(i)}.P^{(i)}}{1+\sum_{j=1}^{NK} b^{(j)}.y^{(j)}.P^{(j)}} \tag{4.2}$$

where:

m_c	Mineral matter content (Non-coal components)
w_c	Equilibrium moisture content
$V_L^{(i)}$	Monolayer amount for i (V_L for gas component i)
$b^{(\kappa)}$	$1/P_L^{(\kappa)}$ for either i or j
$y^{(\kappa)}$	Mole fraction of component i or j in the free gas (vapor) phase.
$P^{(\kappa)}$	Partial pressure of components i or j
NK	Number of mass components ($NK = \kappa$)
j	All the gas components excluding the component i ($j = \kappa - i$)

A general multi-phase, multi components system of water, CH_4, CO_2, N_2 and H_2S is written in the general TOUGH2.2 form (Pruess et al., 1999).

Zarrouk and Moore (2008) fitted the permeability data (Figure 3.6) to curves using an exponential function from McKee et al. (1987):

$$k = k_{\circ} \exp\left(-3.c_f . \Delta\sigma_e\right) \tag{4.3}$$

and

$$\Delta\sigma_e = \sigma_e - \sigma_{e\circ} = \beta(P_{\circ} - P) = \beta\Delta\mathrm{P} \tag{4.4}$$

Here $\sigma_e = \sigma_t - \beta.P$ is the effective stress (N/m^2), σ_t is the total stress (N/m^2), β is a constant for linear elastic material (dimensionless), P is the pore pressure, $\Delta\sigma$ is the increase in effective stress, $\sigma_{e\circ}$ is the initial effective stress, $P_{\circ}$ is the initial pore pressure and ΔP is the pressure drop.

The pore volume compressibility c_f was calculated using equation (4.3).

$$\phi = \phi_{\circ} . \exp\left\{c_f \left(P - P_{\circ}\right)\right\} \tag{4.5}$$

Equation 4.5 is derived from the definition of compressibility at constant temperature

$$c_f = \frac{1}{\phi}\left(\frac{\partial\phi}{\partial \mathrm{P}}\right) \tag{4.6}$$

Equation 4.5 is then combined with the Carman-Kozeny equation that calculates the porosity dependent permeability:

$$k = k_{\circ}\left(\frac{\phi}{\phi_{\circ}}\right)^3 \tag{4.7}$$

Equations 4.5 and 4.7 have previously been implemented in the TOUGH2.2 simulator to calculate the effects of reservoir pressure on porosity and permeability (Zarrouk, 2008; Zarrouk and Moore, 2007; 2008). As in Zarrouk and Moore (2008) an average compressibility was used in this work for all gases (Figure 3.6). More complicated multi-gas models will be implemented when more data becomes available.

4.2 ENTHALPY OF INJECTED GASES

The TOUGH2.2 simulator solves the energy equation along with the mass conservation equations. The energy equation solves for the enthalpy of both liquid and gas. The formulae for calculating enthalpies for the injected gases were derived by Zarrouk (2008) by integrating the polynomial formulae for specific heat capacity given by Felder and Rousseau (1986):

$$\mathrm{H_g}^{(\kappa)} = 1/(\mathrm{MW}^{(\kappa)}) . \sum_{i=0}^{n} \mathrm{A}i^{(\kappa)} . \mathrm{T}^{i+1}/(i+1) \tag{4.8}$$

where:

$\mathrm{H_g}^{(\kappa)}$	Enthalpy of gas κ in kJ/kg
$\mathrm{MW}^{(\kappa)}$	Molar weight of gas κ in kg/kmol
$\mathrm{A}i^{(\kappa)}$	Constants for gas κ given in Table 4.1

T Temperature in °C

Table 4.1. Parameters for equation 4.8 (Felder and Rousseau, 1986).

Gas	$A_0^{(\kappa)}$	$A_1^{(\kappa)}$	$A_2^{(\kappa)}$	$A_3^{(\kappa)}$	$MW^{(\kappa)}$
CH_4 N_2	34.31 29.0	5.469×10^{-2} 2.2×10^{-3}	3.661×10^{-6} 5.72×10^{-6}	-1.1×10^{-8} -2.87×10^{-9}	16.043 28.013
CO_2	36.11	4.23×10^{-2}	-2.89×10^{-5}	7.46×10^{-9}	44.01
H_2S	35.51	1.55×10^{-2}	0.30×10^{-5}	-3.29×10^{-9}	34.08

As injection would occur in the gas phase, with stored gas at surface conditions, ambient temperature of 25 ºC was assumed for the current scenarios. However, higher gas (e.g. flue gas) temperature can be considered.

4.3 ENTHALPY OF DISSOLVED GASES

The enthalpy of gases dissolved in water is calculated by adding the gas phase specific enthalpy of Equation 4.8 and the heat of solution (Battistelli et al., 1997) according to:

$$H_l^{(\kappa)}\left(P^{(\kappa)},T\right) = H_g^{(\kappa)}\left(P^{(\kappa)},T\right) + \Delta H_{sol}^{(\kappa)}(T) \tag{4.9}$$

The heat of solution $\Delta H_{sol}^{(\kappa)}$ of gas (J/kg) was calculated using the expression for the temperature dependence of the equilibrium constant for the chemical reaction of solution (Battistelli et al., 1997). Battistelli et al. (1997) implemented Himmelblau's (1959) equation that relates heat of solution for the different gases to Henry's constant.

$$\left(\frac{\partial \ln K_h^{(k)}(T)}{\partial T}\right)_p = \frac{\Delta H_{sol}^{(k)}(T)}{R(T+273.15)^2 MW^{(k)}} \tag{4.10}$$

To simplify the calculation of the left-hand side of equation (4.8) using Henry's constant K_h^{κ} see Battistelli et al. (1997). Equation (4.10) is rearranged to give the heat of solution.

As gases are injected into the coal seam some of the gas will be dissolved into the water (immobile water) present in the coal. The dissolution reaction is an exothermic reaction (heat of solution), which allows monitoring the temperature of the well block with time during gas injection. This has not been done by other ECBM simulators and is one of the unique features of the TOUGH2.2 simulator. The modelling results (see next section) show significant increase in the well bore temperature which could have implications on the permeability of the coal (reduction due to thermal expansion) around the well during the reinjection of CO_2.

4.4 MODEL DESIGN

ECBM scenarios are typically modelled using a 5-spot well design scenario (Connell, 2008b; Connell and Detournay, 2008; Deng et al., 2006; Gorucu et al., 2005; Korre et al., 2007; Pan and Connell, 2008; Shi and Durucan, 2005a; Zarrouk and Moore, 2008) as shown in Figure 4.1(A). This design involves an injector well in the centre of four production wells. This is done as a first step in a new CBM field development at the appraisal stage. As a CBM play is developed well placement tends to be designed as a grid of relatively evenly spaced wells across a field with a spacing of 80, 160 or 320 acres (0.33, 0.65, 1.3 km^2) depending on reservoir drainage properties. As such, the 5-spot pattern is not very representative to full scale ECBM developments. Converting a production well to an injector well would create this

9-spot well design scenario (Figure 4.1(B)). The 9-spot design has been used for this study. The modelling comparison study of reservoir simulators conducted by Law et al. (Law et al., 2003a; 2002; 2003b), used the 5-spot pattern as the more complex 9-spot differencing scheme could not be handled by some of the simulators participating in the study. In both scenarios a quarter of the symmetric design is modelled to save on computational time.

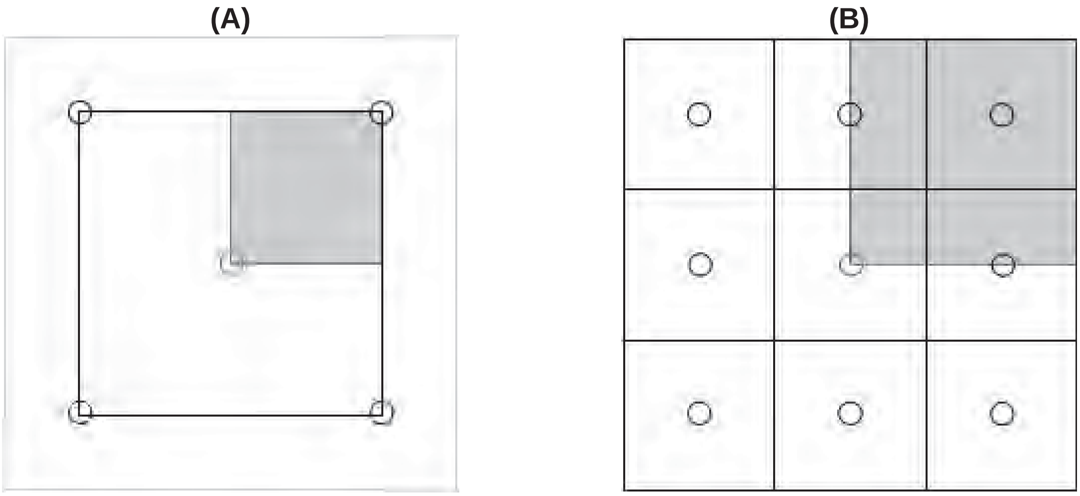


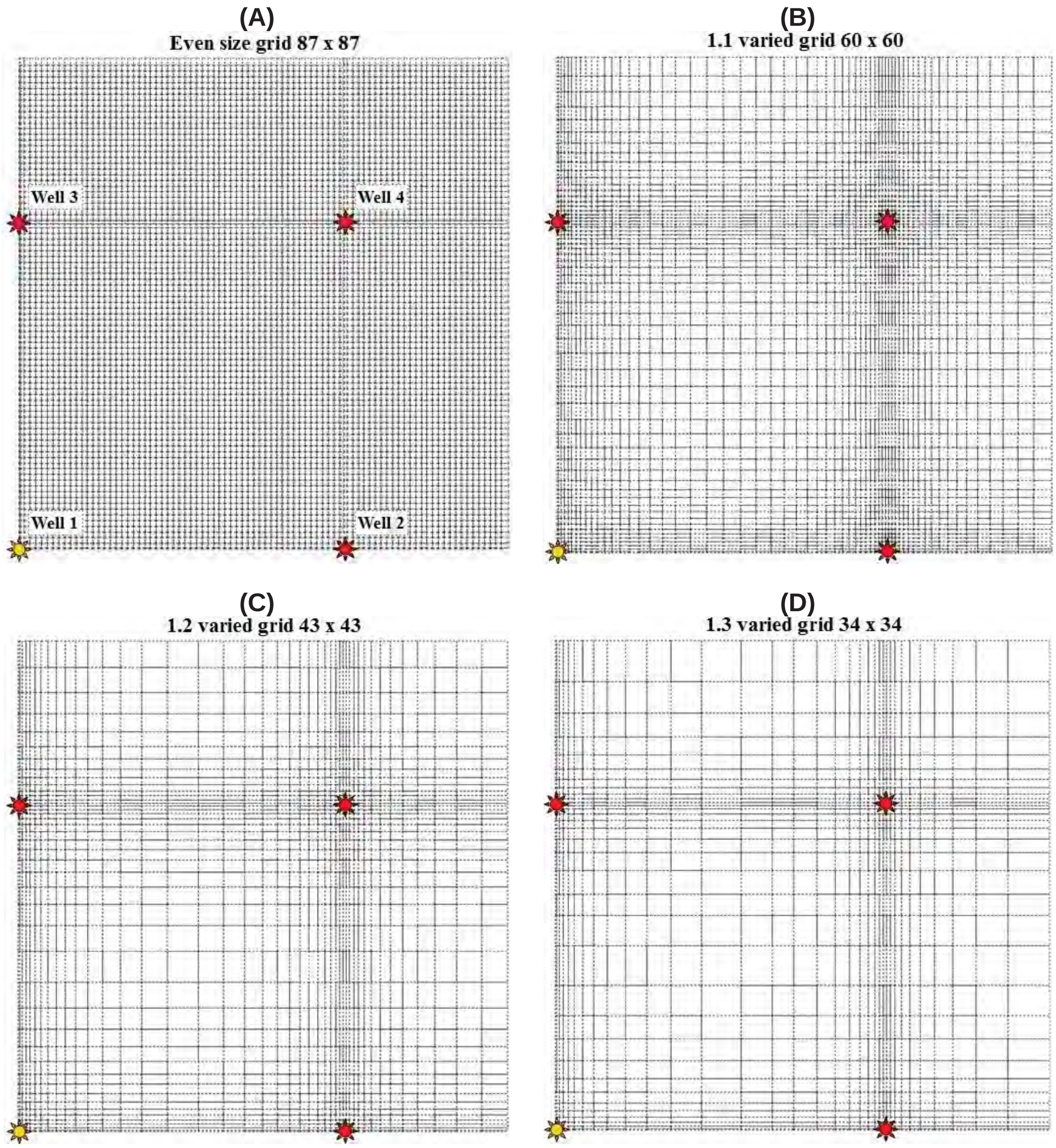
Figure 4.1. Model designs with modelled area (1/4) marked in grey, production wells shown as black circles and the injector well marked in red (A) 5-spot model design and (B) 9-spot model used in this study.

It is also common that only the seam in the area of interest is modelled (Deng et al., 2006; Korre et al., 2007; Law et al., 2003a; 2002; 2003b; Shi et al., 2008; Zarrouk and Moore, 2008) separate from the surrounding geology. Multiple layers above and below the coal seam were modelled by Connell (2008b) and Connell and Detournay (2008) however they do not differentiate the overlying material into different geological units. It was decided to model the scenarios here to the ground surface as dewatering and depressurizing the coal unit will affect the surrounding units which may in turn affect production and CO_2 storage. In addition, some scenarios were re-run with boundary conditions i.e. atmospheric block on top and basement rock acting as a constant pressure boundary (see Zarrouk and Moore, 2007). If desired the TOUGH2.2 simulator can include the effect of the local hydrological setting, such as the influence of rain infiltration and possible communications with rivers, lakes and shallow ground water aquifers on the hydrostatic pressures, although these influences have not been addressed in this study.

The scenarios were modelled at 80, 160 and 320 acre well spacing for both the Ruawaro and Mangapiko locations to simulate potential field development designs, with the Ohinewai location only being modelled at 80 acre spacing because of its very low CH_4 content and potential for CO_2 breakthrough to the surface (see section 6.8). Regardless of model size, the size of the well block and the number of blocks were kept the same. Stimulation of CBM wells is also common in field development to increase the access to, and volume of, the zone of low pressure around the well bore. For the 80 acre scenario both stimulated and non-stimulated scenarios were considered with only stimulated wells included in the larger area models (160 and 320 acres). Stimulation was simulated as a fracture (zone of higher permeability see Table 3.6) with a half length of approximately 50 - 60 m extending to the left and right of each well block. This is not unrealistic as the fracture will form perpendicular to the direction of principal stress underground. For the Ohinewai scenario the fracture was connected through all three coal layers.

4.5 MESH INDEPENDENCE STUDY (MESH REFINEMENT STUDY)

The finer the computational grid the more accurate the model results, however, having a large number of blocks in the model dramatically increases processing (simulation) time. To justify the use of a grid with fewer blocks for the scenarios discussed above, a mesh refinement study was undertaken where the results of a fine grid were compared to those generated by coarser grids. This part of the study used an 80 acre (0.33 km^2) 1 layer model, without stimulation, with the size of the well blocks maintained for each grid. The well block of the full well (well 4) was 5 x 5 m, 2.5 x 5 m for the half wells (wells 2 and 3) and 2.5 x 2.5 m in the central quarter well (well 1). The finest grid was designed with even sized blocks away from the wells 10 x 10 m in size (Figure 4.2(A)). Grids with blocks of varying size were designed to be fine around the areas of primary interest and best known data, the well blocks, and coarse in areas away from the well blocks. Four different varied grids were produced by increasing each row of blocks by an increment of 1.1, 1.2, 1.3 and 1.4 times respectively (Figure 4.2(B) – (E)).



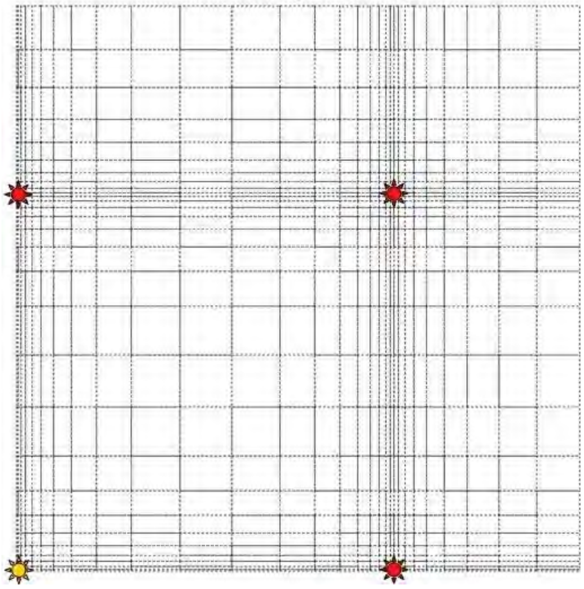


Figure 4.2. Grids used for the mesh refinement study yellow star indicates the injection well and the red stars the production wells (A) Even size grid with 7569 blocks, (B) 1.1 varied grid with 3600 blocks, (C) 1.2 varied grid with 1849 blocks, (D) 1.3 varied grid with 1156 blocks, and (E) 1.4 varied grid with 841 blocks.

As the separation of CO_2 from flue gas is currently the major cost driver for CO_2 sequestration (Robertson, 2008), and the Waikato coalfields have several local point source emitters, it was decided to trial both pure CO_2 and different flue gas compositions. CO_2 has been seen elsewhere to decrease the permeability of coal, while N_2 can enhance permeability (Deng et al., 2006; Harpalani et al., 2006; Shi et al., 2008). Flue gas injection comes at a cost of very early breakthrough of N_2 into the production wells. The level of N_2 permitted in produced gas will be dependent on the end use. This could be an electricity generator with high tolerance to gas impurities. The three different injection gases selected for injection were:

- Pure CO_2
- Flue gas typical of a gas fired generator with composition 87% N_2, 13% CO_2 (Connell, 2008b; Deng et al., 2006; Harpalani et al., 2006)
- Underground coal gasification (UCG) spent fuel gases of composition 89.2% N_2, 10.8% CO_2 and 0.04% H_2S.

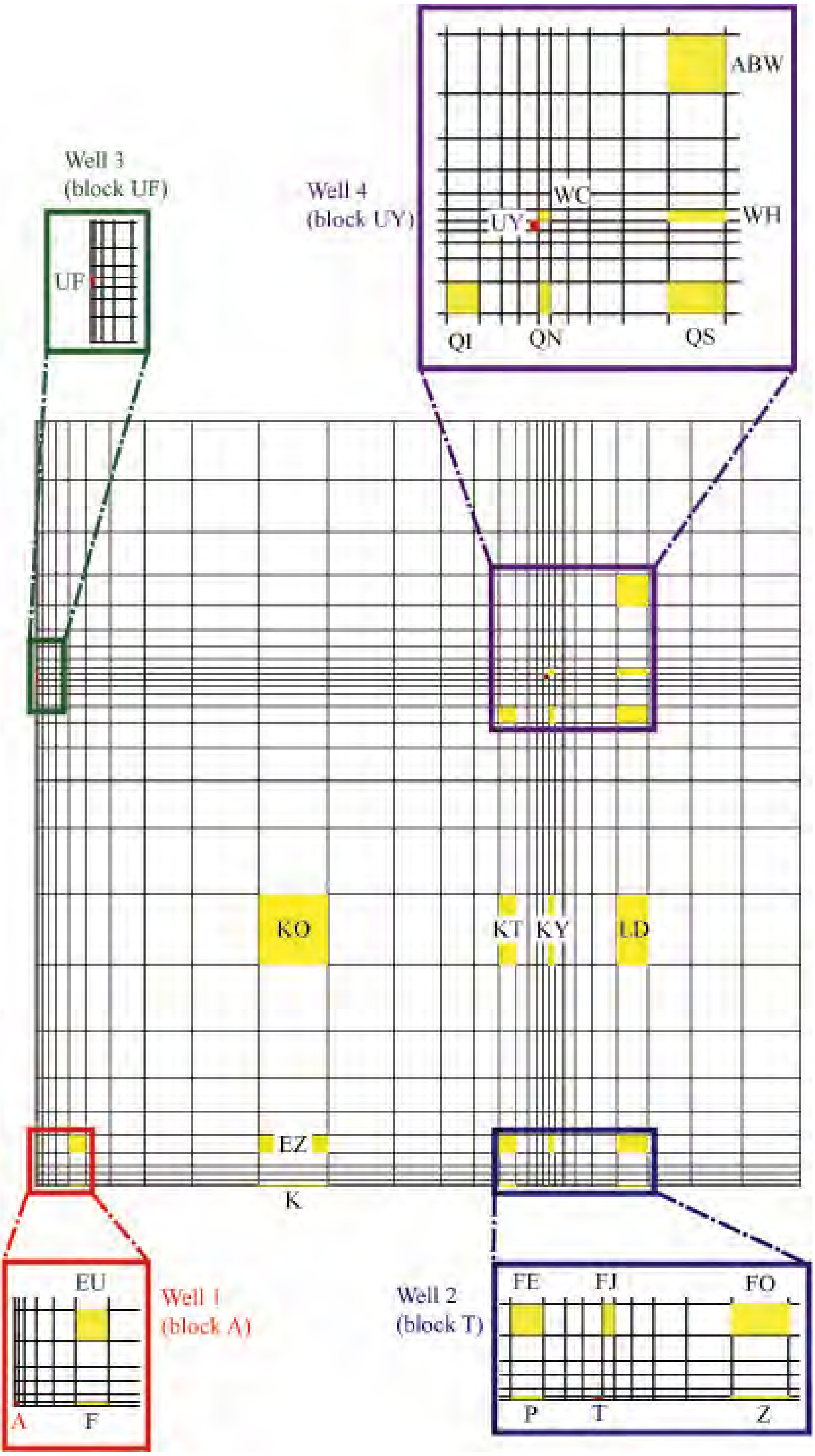


Figure 4.3. Location of CO_2 surface monitoring sites (yellow) and close ups of well blocks in the model design; well locations are in red.

5.0 RESULTS AND INTERPRETATION

5.1 PRODUCED GAS COMPOSITION

The comparison of produced gas composition, assuming reservoir gas composition of 100% CH_4 versus mixed gas (Table 3.5), was completed prior to the main scenarios prepared for this study and hence was conducted with a different grid structure. As such, the production rates presented in Figure 5.1 cannot be compared to those presented later in this report.

It can clearly be seen in Figure 5.1 that, even for such a relatively 'pure' CH_4 reservoir such as the Huntly coalfield, assuming 100% CH_4 composition considerably over estimates the peak of the CH_4 production rate curve. This in turn has implications for financial models and possibly even field infrastructure design.

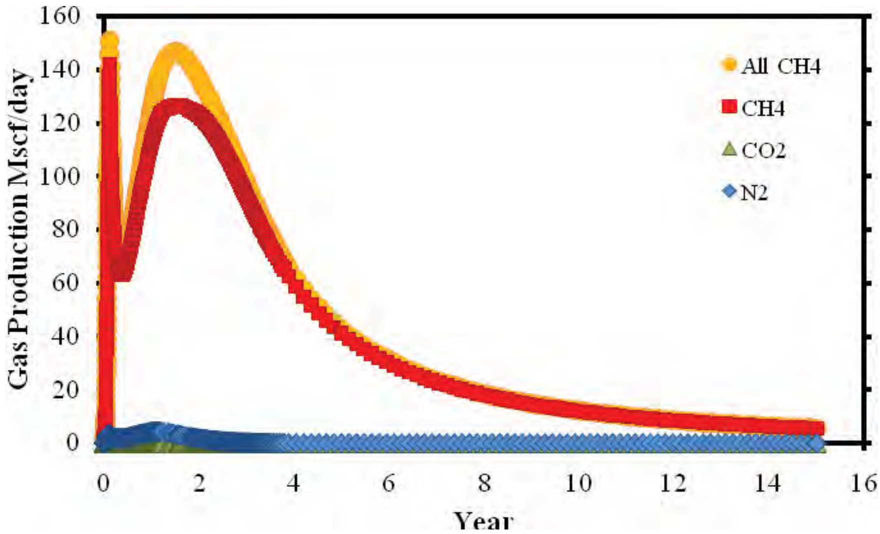


Figure 5.1. Production rates assuming reservoir gas composition of 100% CH_4 versus 97% CH_4, 0.5% CO_2 and 2.4% N_2.

When plotting the percentage composition of produced gas (gas quality) over time (Figure 5.2) it is revealed that production gas composition is not stable. Production of N_2 is proportionally higher during the first few years of production and stable in the latter years as a result of its low adsorption affinity in coal. In contrast, the proportion of CO_2 steadily increases with time, resulting from its preferential adsorption in coal over CH_4 ($N_2 < CH_4 < CO_2$ (Yee et al., 1993)). While not posing an issue for the development of the Waikato coalfield, possible changes in produced gas composition with production time should be considered in any future prospective site assessments.

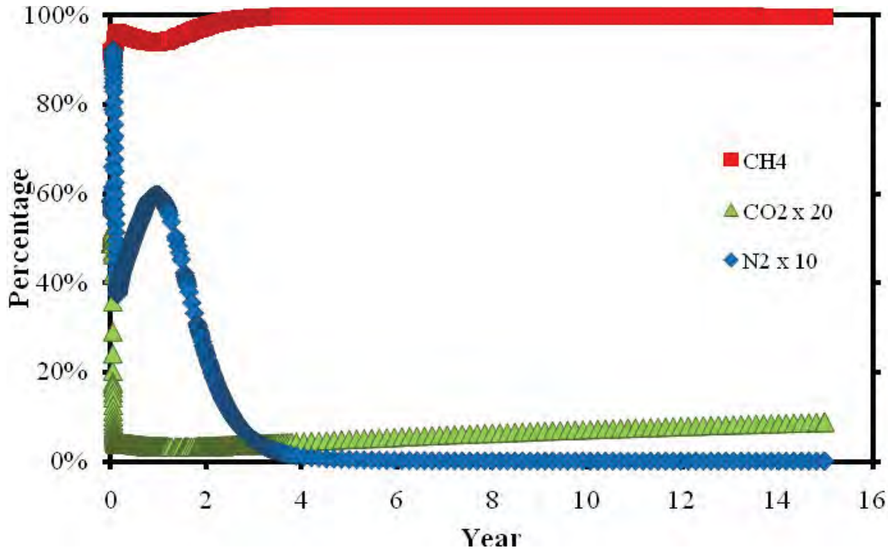


Figure 5.2. Change in produced gas composition with production time.

5.2 MESH INDEPENDENCE STUDY

The results from the mesh independence study are presented in Figure 5.3. As all four wells showed similar production rates for all scenarios only the results for well 2 are presented here. The results for the coarsest scenario, the 1.4 varied grid, are the same as those produced using the finest grid, the even sized grid, hence the 1.4 varied grid was used for modelling the 3D scenarios for this study. This dramatically decreased simulation run time.

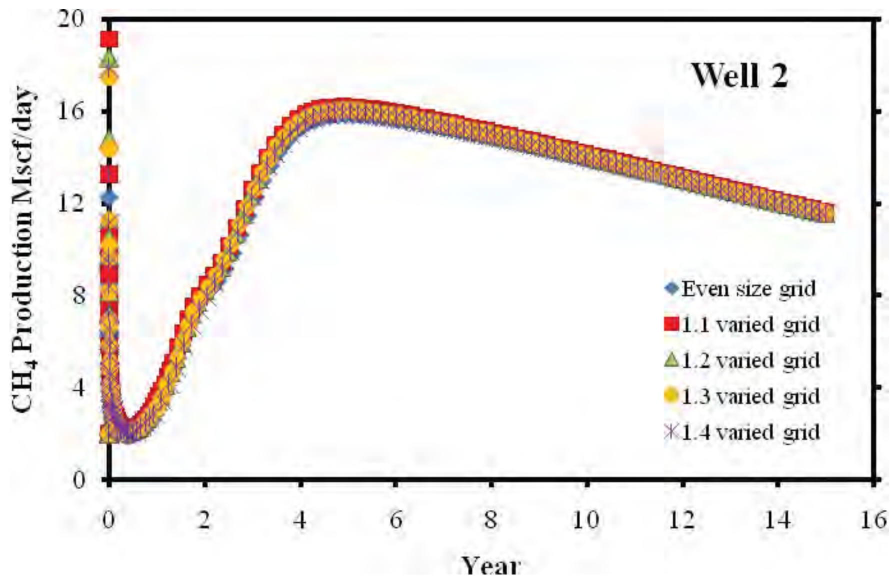


Figure 5.3. CH_4 production rates for well 2 of the five different grids used in the mesh refinement study. The scenario is based on the Ruawaro data, is single layer and has no well stimulation.

5.3 CBM PRODUCTION

To consider the enhancement on CBM production by injected gases it was first necessary to model production only scenarios. The three selected locations have different depths, gas contents and gas adsorption capacities, with Mangapiko also having a considerably higher permeability, as discussed in section 4. The CH_4 production rates for a stimulated (hydraulically fractured) production well (well 2) for each location are presented in Figure 5.4. Plainly from these results the Ruawaro location would be favoured for CBM development, and as such has been treated as our primary scenario, with Ohinewai unlikely to ever be considered. To keep the results comparable it was decided for this study to model 5 years production prior to gas injection for all scenarios so that the reservoir has undergone some depressurization.

As reported for production rates from commercial CBM plays in the U.S.A. (Mavor and Vaughn, 1998), after the initial gas peak decline for the Ruawaro and Mangapiko locations production rates increase again. This occurs as a result of continued pressure reduction in the reservoir from production and shrinkage of the coal matrix from gas desorption creating an increase in absolute permeability. This increase is more pronounced at the Mangapiko location and is likely a result of the considerably higher and faster dewatering/depressurization possible because of the greater coal permeability.

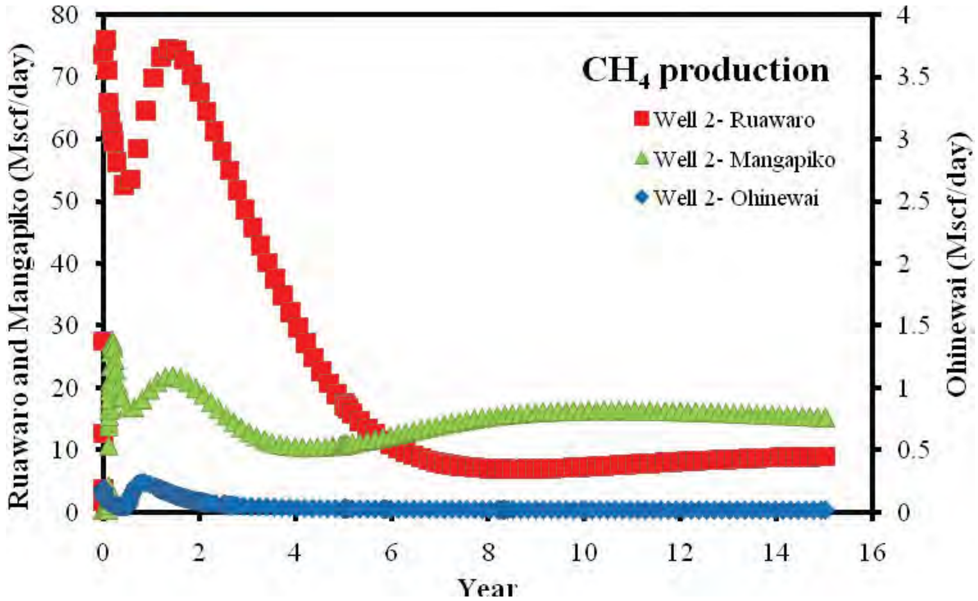


Figure 5.4. CH_4 production from stimulated wells at the Ruawaro, Mangapiko and Ohinewai locations.

To examine the difference between production from unstimulated and stimulated wells and their effect on low and high permeability scenarios pressure maps for each layer in the Ruawaro scenario at time = 0, t = 15 years with unstimulated wells and t = 15 years with stimulated wells are presented in Figure 5.5, Figure 5.6 and Figure 5.7 respectively, and for the Mangapiko location in Figure 5.8, Figure 5.9 and Figure 5.10.

Considering the Ruawaro location, depressurization resulting from production /dewatering from the coal seam in layer 8 is identifiable as high as layer 4 (which showed a 0.2 MPa reduction). For the unstimulated scenario seam pressure has been reduced to around 1 MPa in the coal seam with a small area around the wellbores reduced to 0.8 MPa. This area of decreased pressure in the near well vicinity is recognisable as high as layer 6. Drainage in the stimulated scenario is more successful with the coal seam pressure being reduced again to 1 MPa but with a larger area reduced around the wellbore to < 0.5 MPa.

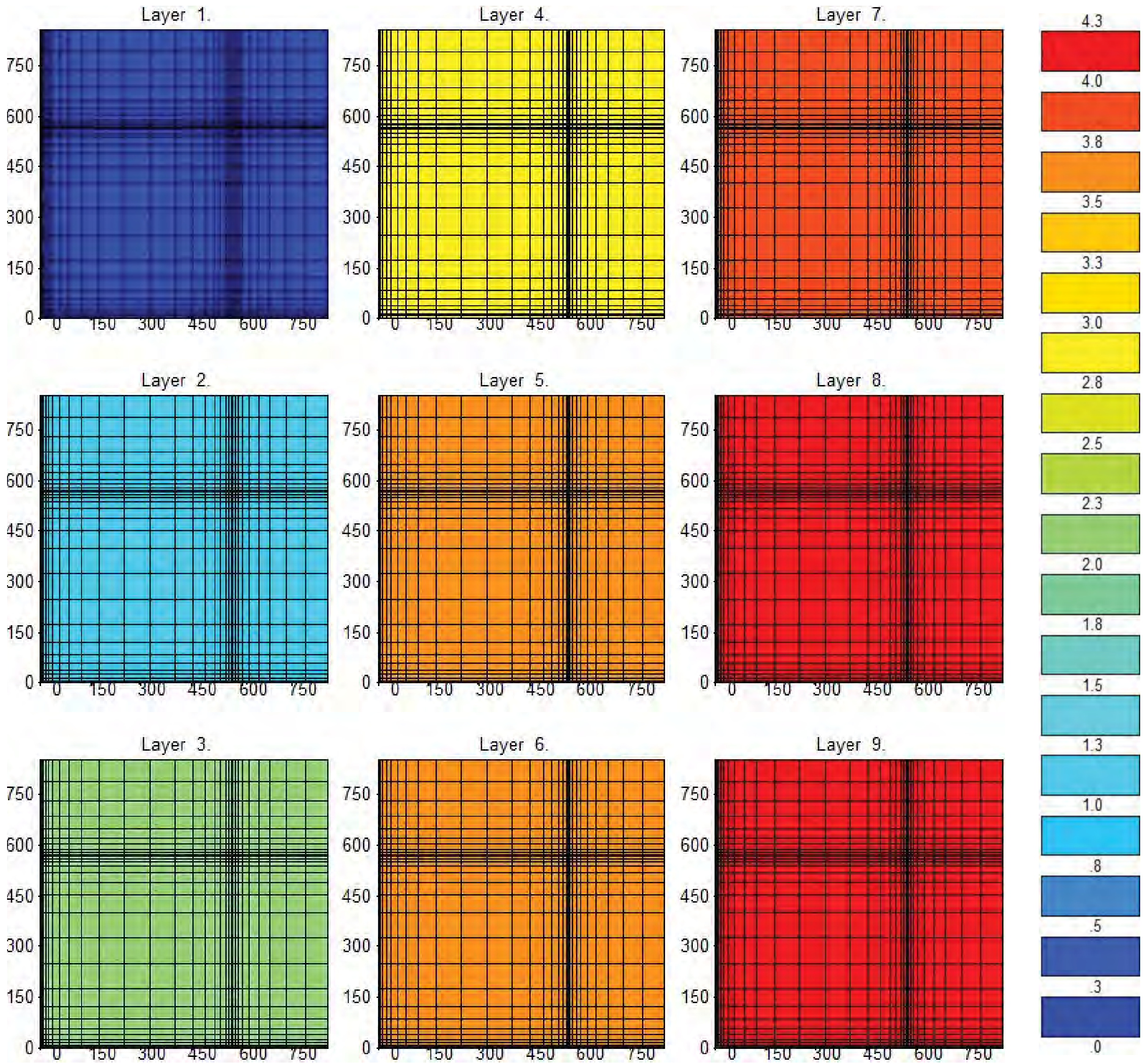


Figure 5.5. Pressure in MPa of layers in the Ruawaro scenario prior to field production (t=0).

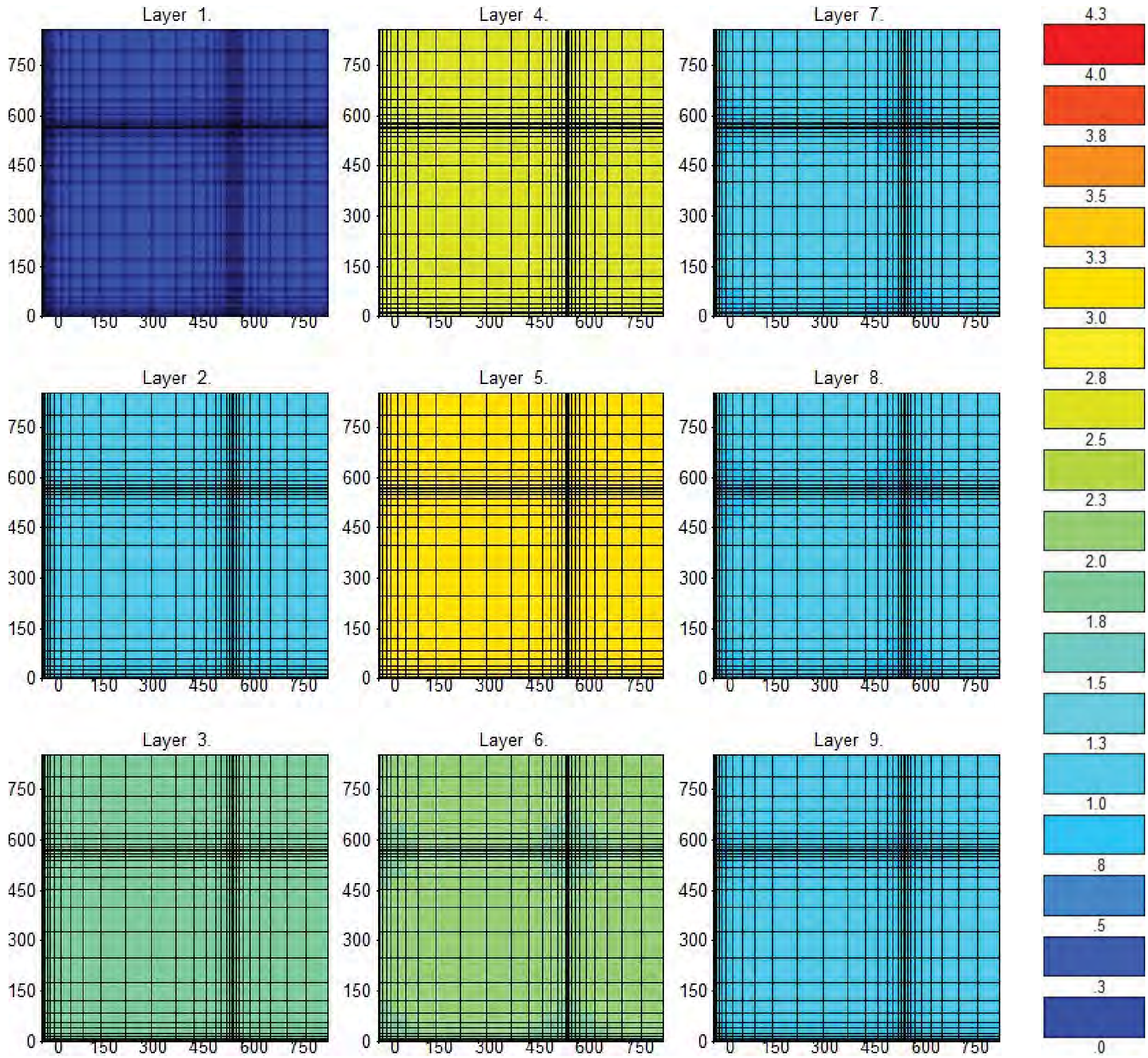


Figure 5.6. Pressure in MPa of layers in the Ruawaro scenario after 15 years of field production (t=15) from unstimulated wells.

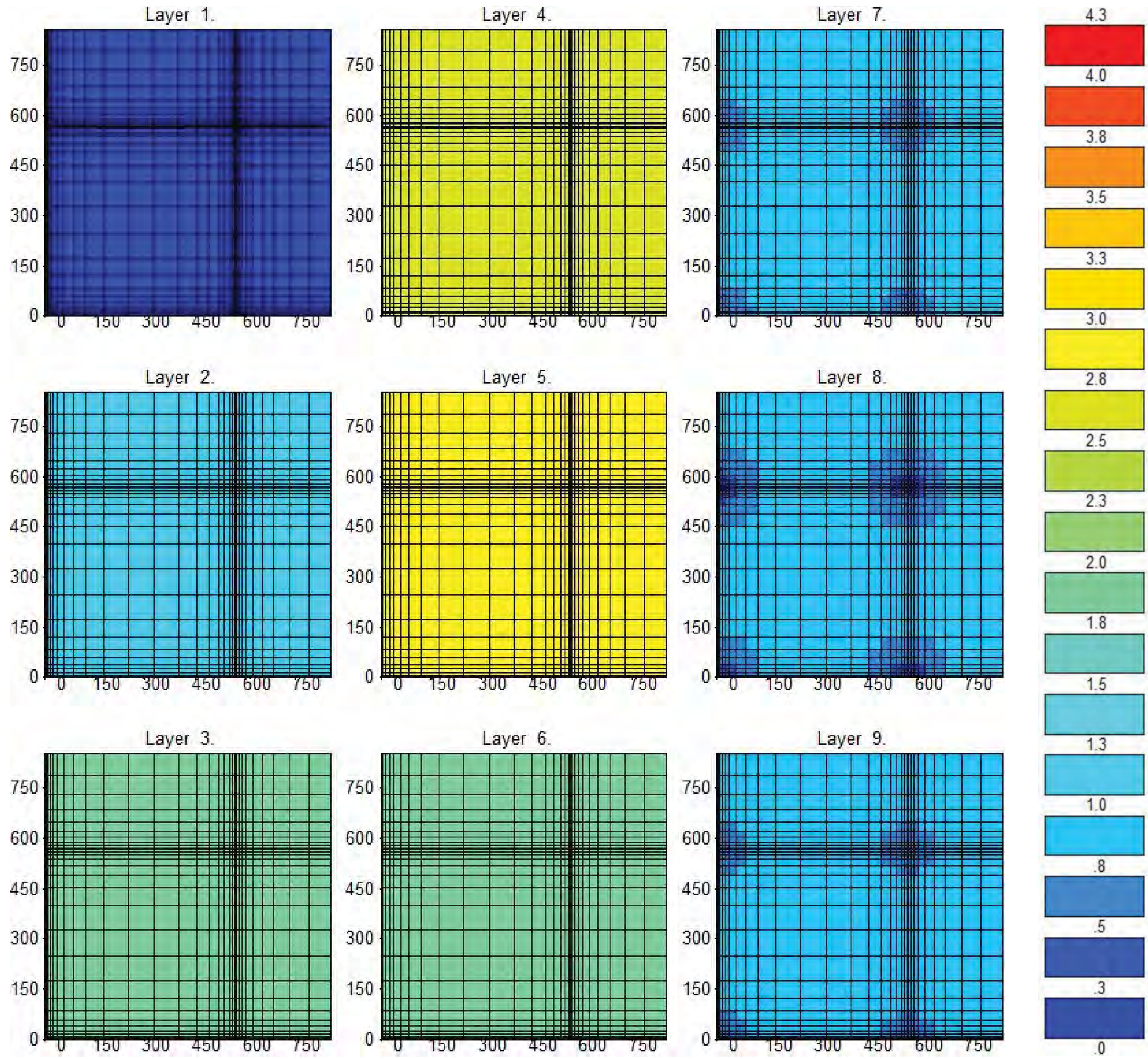


Figure 5.7. Pressure in MPa of layers in the Ruawaro scenario after 15 years of field production (t=15) from stimulated wells.

The higher permeability of the coal seam at the Mangapiko location results in much greater drainage of the coal seam for both unstimulated and stimulated scenarios. In both cases large areas are reduced to < 0.6 MPa with the stimulated scenario depressurizing the whole seam to this level. The effect of this greater drainage capacity on gas injection will be discussed later. The major implications of Figure 5.5 to Figure 5.10 are that for the Waikato coalfield, stimulated wells will perform better than unstimulated wells and that production from the coal seam does not only affect the coal seam. The coal seam should not just be modelled as an isolated unit as no geological unit will be completely impermeable. These figures reinforce the need for permeability testing of the overlying strata.

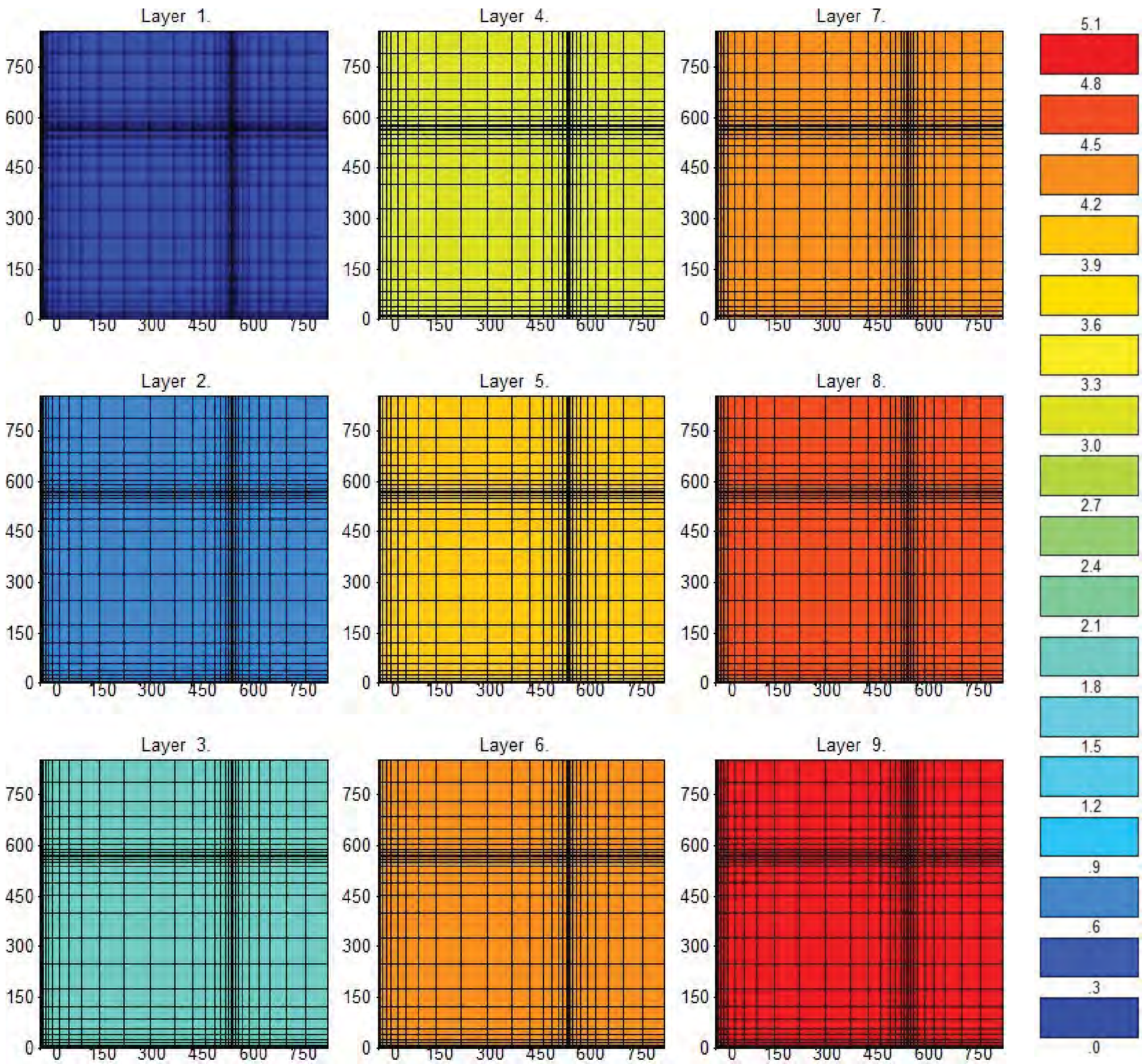


Figure 5.8. Pressure in MPa of layers in the Mangapiko scenario prior to field production (t=0).

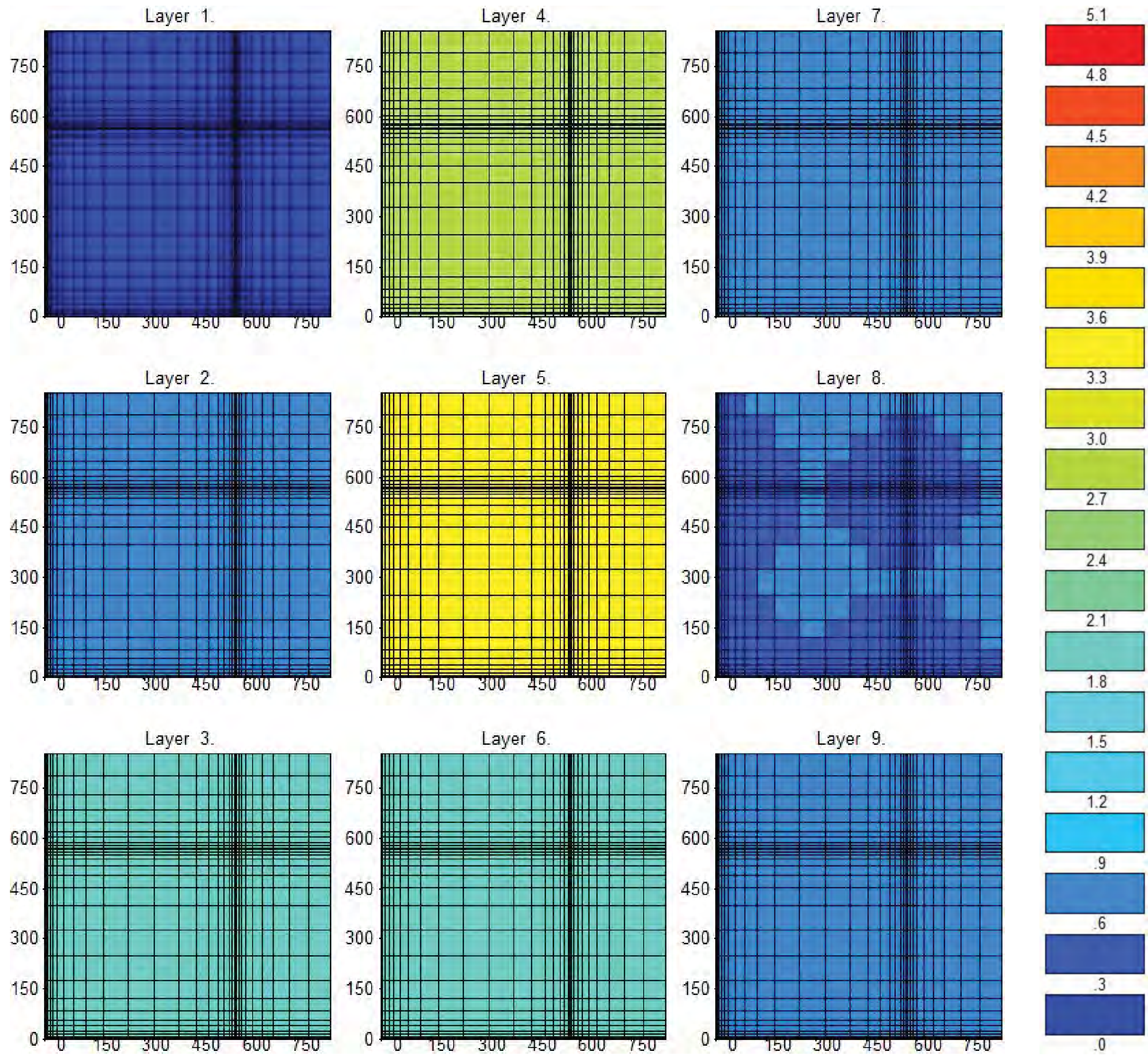


Figure 5.9. Pressure in MPa of layers in the Mangapiko scenario after 15 years of field production (t=15) from unstimulated wells.

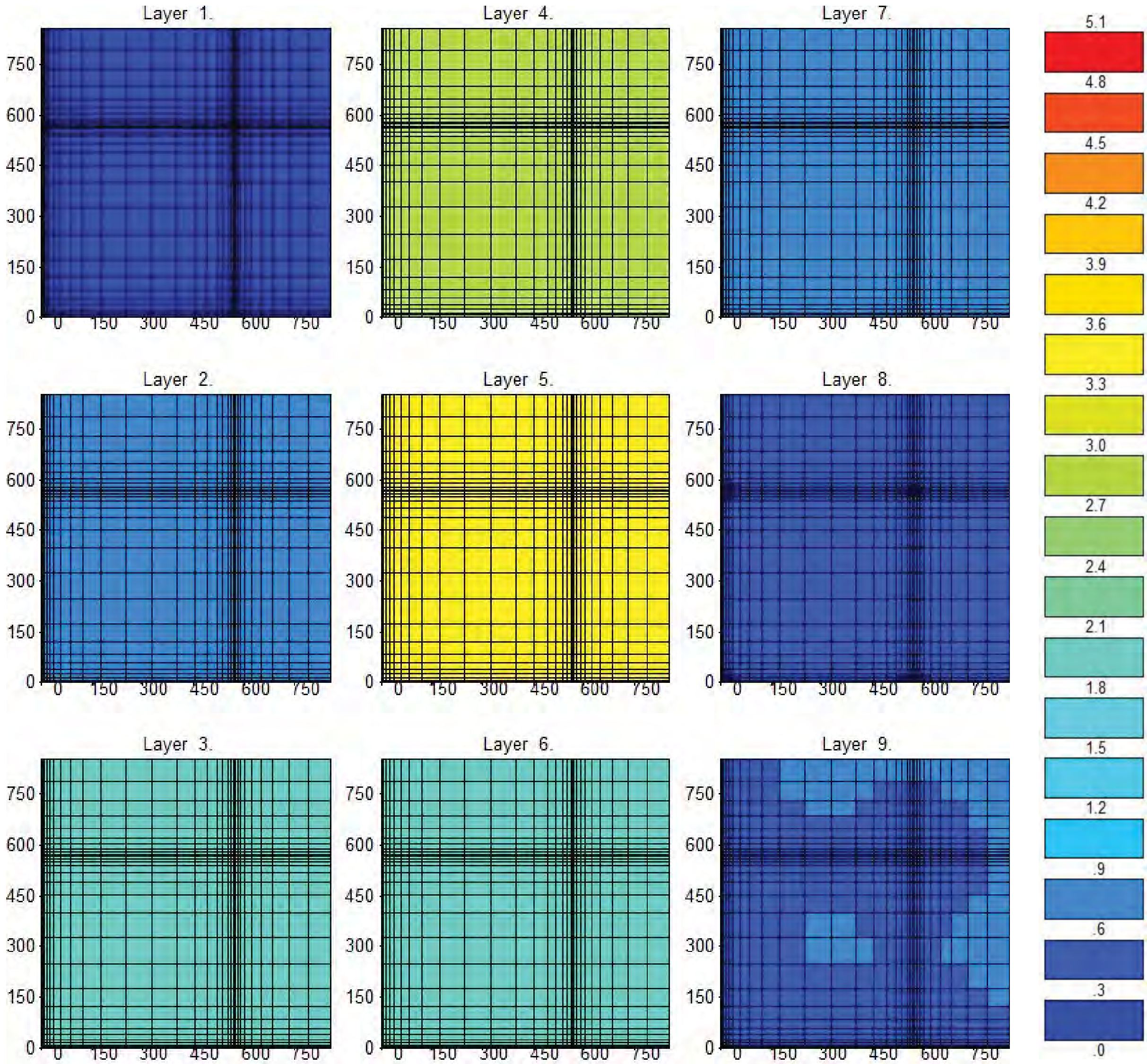


Figure 5.10. Pressure in MPa of layers in the Mangapiko scenario after 15 years of field production (t=15) from stimulated wells.

A comparison of CH_4 production rates for different field development scenarios at the Ruawaro and Mangapiko locations are presented in Figure 5.11 and Figure 5.12 respectively. The greater permeability at the Mangapiko area results in a delay in gas production because of better water drainage and hence a larger volume of water produced. For both locations stimulated wells on any spacing perform better than the unstimulated 80 acre (0.33 km^2) wells. Therefore, although injection scenarios were completed for unstimulated wells, the results will not be presented in this report as field development using this scenario is unlikely.

At Ruawaro, the 80 acre well spacing clearly produces the gas reserves in the shortest amount of time, resulting from faster reservoir depressurization by well interference, while less difference is noticed at the Mangapiko location because of the greater permeability and hence the ease of gas and water to flow towards the production well. Optimal field spacing will depend on the coal permeability, fracture half length and the long term field development strategy. For the 80 acre well spacing gas injection after 5 years of production appears reasonable however for larger well spacing this time frame may need to be extended.

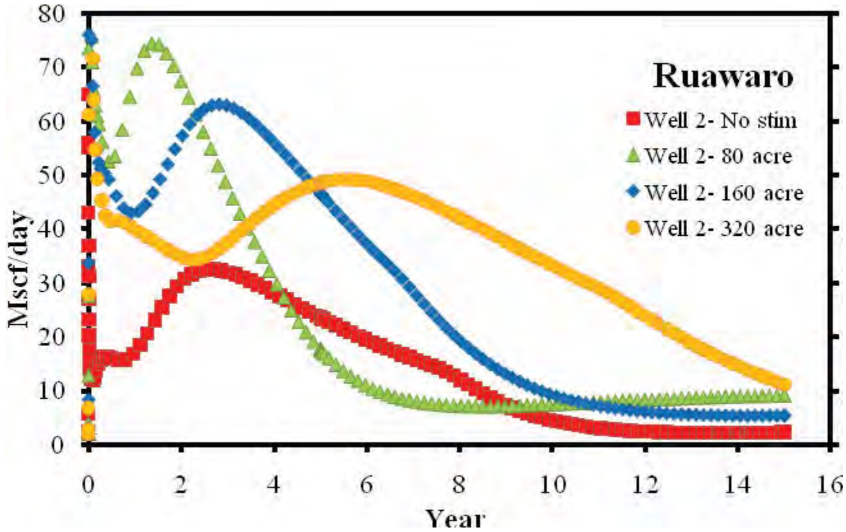


Figure 5.11. CH_4 production rates for different scenarios at the Ruawaro location: 80 acre with no well stimulation, 80 acre stimulated, 160 acre stimulated and 320 acre stimulated.

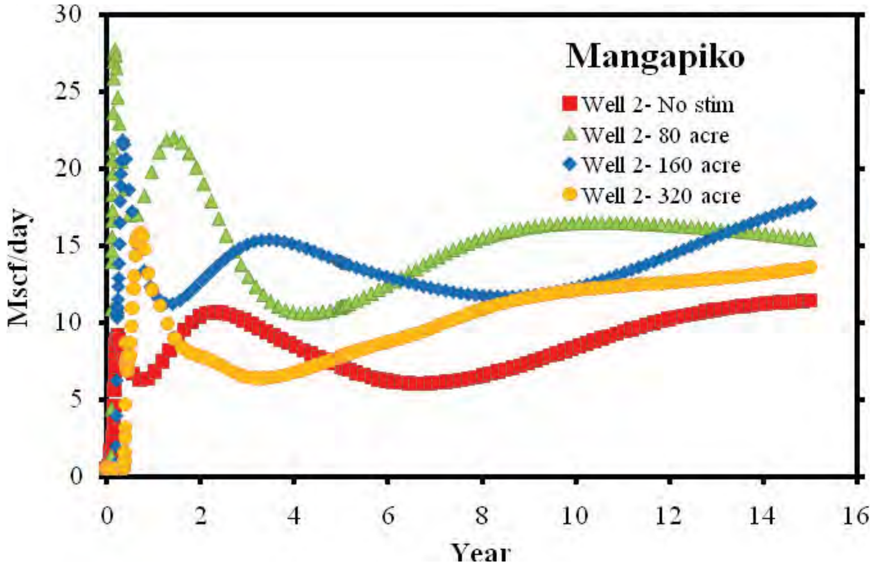


Figure 5.12. CH_4 production rates for different scenarios at the Mangapiko location: 80 acre with no well stimulation, 80 acre stimulated, 160 acre stimulated and 320 acre stimulated.

5.4 ECBM SCENARIOS- RUAWARO

5.4.1 80 acre well spacing

Results from the pure CO_2 gas injection scenarios into the Ruawaro location are presented in Figure 5.13. Peak CH_4 production occurs at year 2 with a maximum production rate of around 75 Mscf/day[1] (2100 m^3/day) - for the given fracture stimulation. A small enhancement in CH_4 production rates from well 2 (in line with stimulated fracture orientation) can be recognised from around 8 years for the 5 and 10 tonne/day injection rate scenarios and from 7 years for the 20 tonne/day scenario. Increased production resulting from injection had not reached well 4 (diagonal from the injection well) by the end of the modelled period.

[1] Usual practice is to use Mscf to represent thousand standard cubic feet (= 28.3 m^3, or ~ 1 GJ).

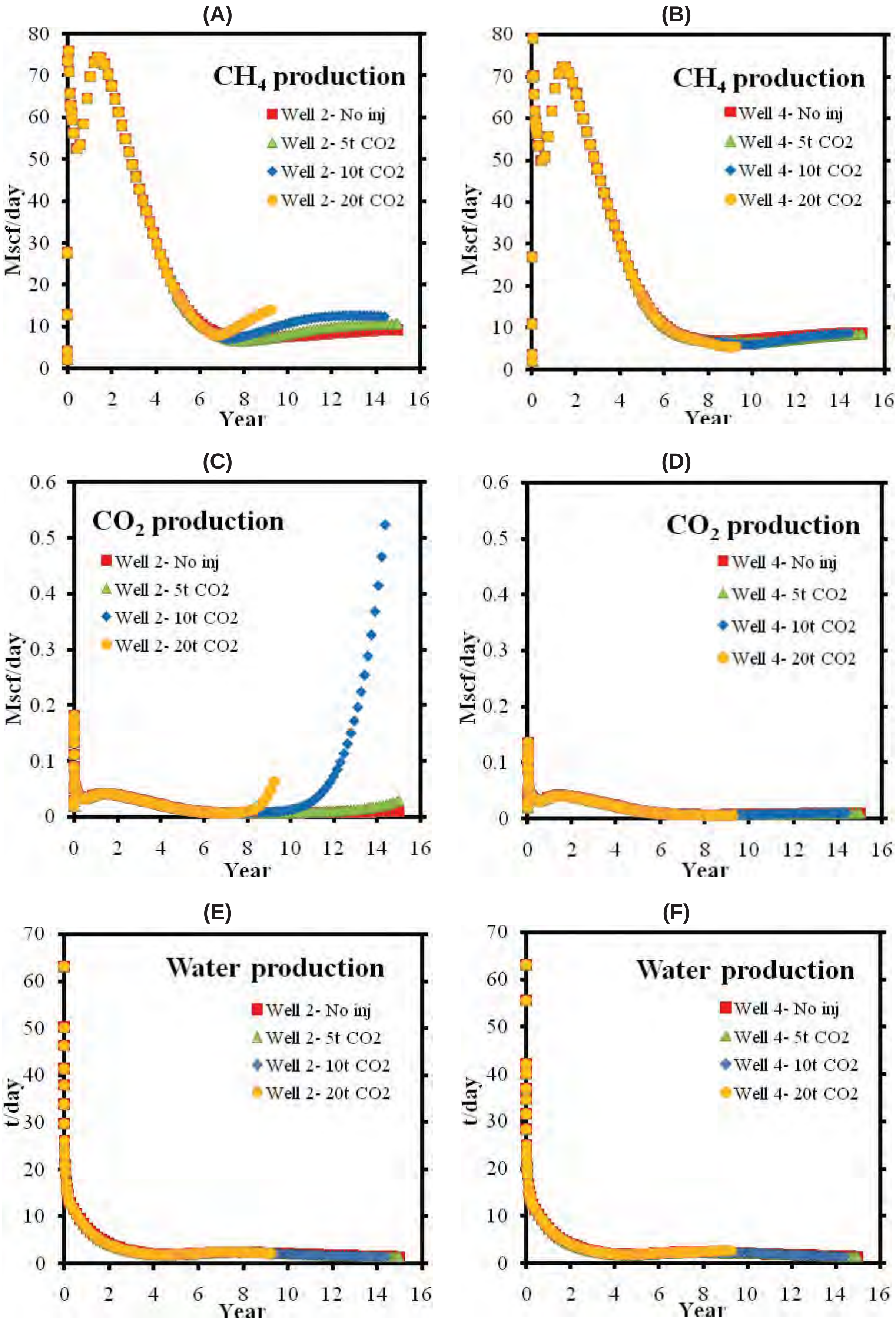


Figure 5.13. Results for CO_2 injection scenarios at the Ruawaro location with 80 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) water from well 2, and (F) water from well 4.

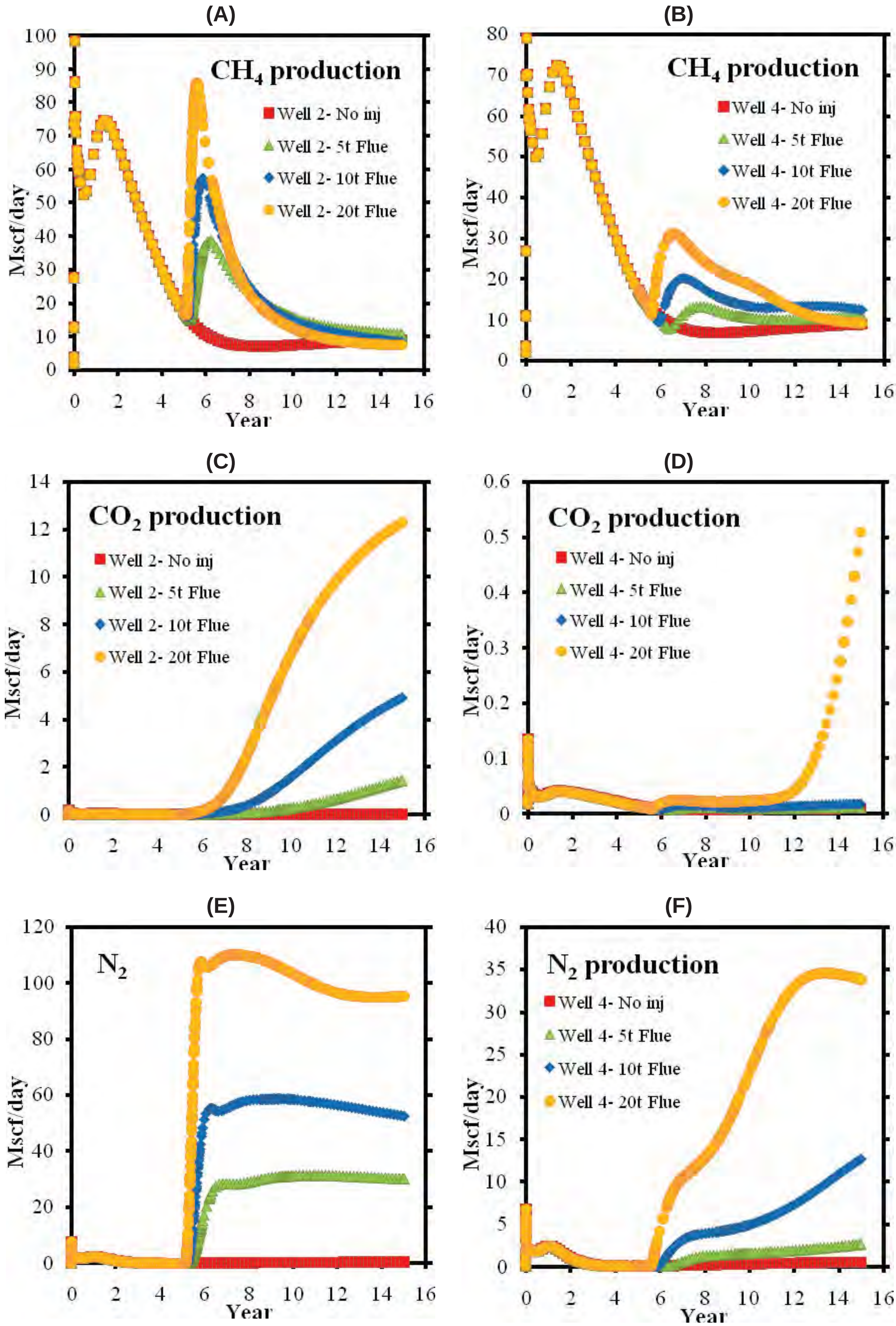
Breakthrough of injected CO_2 gas can be seen in well 2 from 14 years for 5 tonne/day injection, 10 years for 10 tonne/day and 8 years for 20 tonne/day injection. When CO_2 breakthrough occurs, the increase in CO_2 production is asymptotic suggesting arrival of the CO_2 as a front rather than diffuse movement through the coal. This front at well 2 is likely aided by the fracture orientation between wells 1 and 2. Injected CO_2 had yet to reach well 4 and no influence of the gas injection could be seen in the water production rates from either well.

The 10 tonne/day scenario ceased running at 13.5 years while the 20 tonne/day scenario stopped at 8.5 years. In field trials injection rates generally decrease with time as the coal in the vicinity of the wellbore adsorbs CO_2. As injection rates do not fluctuate in the current model design it is thought the model ceased when there was no more space in which to inject gas as the nearby coal was 100% gas saturated, had adsorbed gas to its capacity and the gas was not able to move away fast enough to create further space (a result of permeability reduction/coal swelling).

Results from the flue gas injection scenarios into the Ruawaro location are presented in Figure 5.14. A significant enhancement in CH_4 production rates occurs in both wells with the enhancement occurring within 6 months of the onset of injection in well 2 and between 5.5 and 6.5 years depending on the quantity of injected gas in well 4.

Unfortunately, breakthrough of injected gases is almost simultaneous with the indentified CH_4 enhancement. The onset of CO_2 breakthrough occurs at 5.5, 6.5 and 8 years in well 2 for 20, 10 and 5 tonne/day injection scenarios respectively, and around 10 years for 20 tonne/day injection in well 4. The increased CO_2 production in well 4 between 5.5 and 10 years more likely results from enhanced production rather than injected gas breakthrough. In contrast to the pure CO_2 scenario, although CO_2 breakthrough occurs earlier, the increase in production rate is more gradual showing gas movement has been aided by the presence of N_2 allowing CO_2 to move faster and further into the reservoir, by reducing the partial pressure of CO_2, and allowing adsorption further from the wellbore (also suggested by these models running to completion).

The breakthrough of N_2 is both immediate and dramatic in well 2. Although 20 tonne/day of flue gas injection makes CH_4 production rates very attractive, the significant amount of N_2 also produced may yield the production gas unusable. The selected rate of injection will depend on the requirements of the end user as well as the number of production wells online producing relatively pure methane available for blending the gas quality. The arrival of N_2 at well 4 is more gradual and only reaches production rates less than half those seen at well 2. The first bend in the curve is likely a result of the gas reaching the higher permeability fracture zone then rates increase again as the main front reaches the well.


(A)
CH4 production
Well 2- No inj
Well 2- 5t Flue
Well 2- 10t Flue
Well 2- 20t Flue
Mscf/day
Year
(B)
CH4 production
Well 4- No inj
Well 4- 5t Flue
Well 4- 10t Flue
Well 4- 20t Flue
Mscf/day
Year
(C)
CO2 production
Well 2- No inj
Well 2- 5t Flue
Well 2- 10t Flue
Well 2- 20t Flue
Mscf/day
Year
(D)
CO2 production
Well 4- No inj
Well 4- 5t Flue
Well 4- 10t Flue
Well 4- 20t Flue
Mscf/day
Year
(E)
N2
Mscf/day
Year
(F)
N2 production
Well 4- No inj
Well 4- 5t Flue
Well 4- 10t Flue
Well 4- 20t Flue
Mscf/day
Year

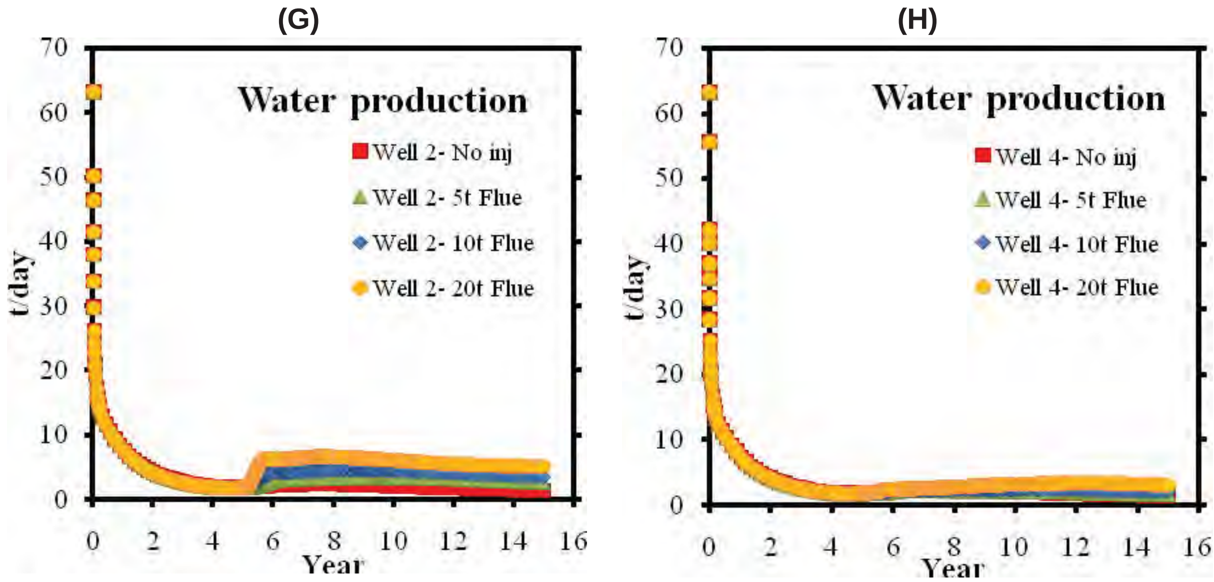


Figure 5.14. Results for flue gas injection scenarios at the Ruawaro location with 80 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) N_2 from well 2, (F) N_2 from well 4, (G) water from well 2, and (H) water from well 4.

Not only does the front of injected gas flush the reservoir of in situ gas, it also flushes the reservoir of free water in areas not yet drained by the production wells, as confirmed by the increased water production rates in well 2. This needs to be considered in field design plans as most CBM produced water is not dischargeable at surface without either dilution or treatment.

The results from the injection of UCG flue gas scenarios into the Ruawaro location were very similar to those for the flue gas scenarios presented above (resulting from similar N_2 and CO_2 compositions). Hence only well 2 results are presented in Figure 5.15.

Onset times for CH_4 enhancement and injected gas breakthrough are the same as those seen for the flue gas scenario. As the proportions of gases were slightly different, more N_2 and less CO_2, the N_2 production rate is higher and the CO_2 production rate is lower. The enhanced water production rates are also the same as those seen above. Production rates of H_2S increase from zero at around 14 years for the 10 tonne/day injection scenario and at 10 years for 20 tonne/day injection. The longer time to gas breakthrough, as compared to CO_2, results from coal having a greater adsorption capacity for H_2S than for CO_2 (Figure 3.5). Although the production rates for H_2S are very low, it is a very toxic gas and may also cause damage (corrosion) to surface equipment. As such, it may be opted to shut in production wells once H_2S is identified in production gas composition. It was decided not to model UCG flue gas injection for other locations and spacing because of the similarity of results to those of flue gas.

The effect of re-injecting CBM produced waters in the vicinity of a producing play was investigated by injecting water directly into the coal seam with the results being presented in Figure 5.16.

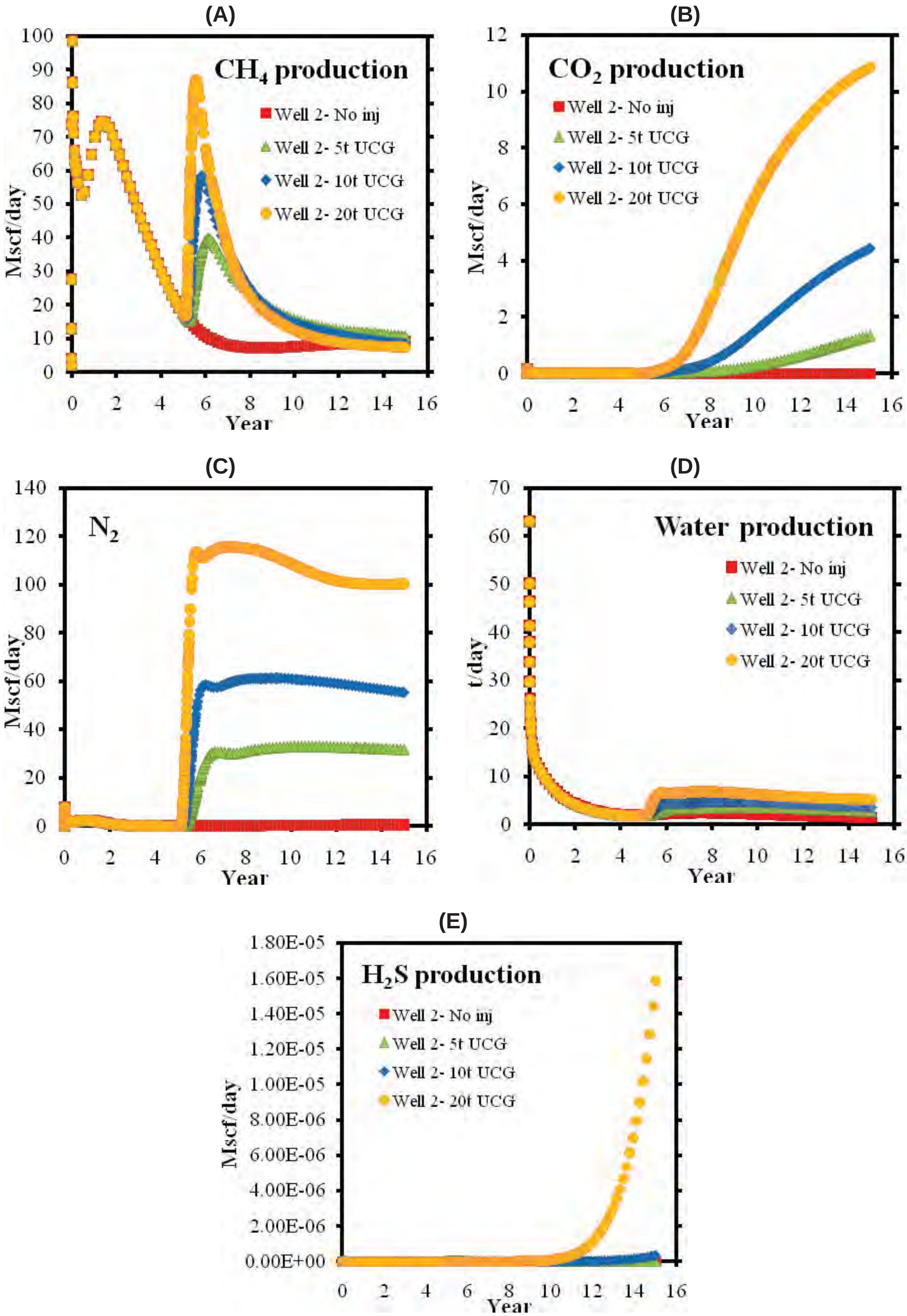


Figure 5.15. Results for UCG flue gas injection scenarios at the Ruawaro location with 80 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CO_2 from well 2, (C) N_2 from well 2, (D) water from well 2, and (E) H_2S from well 2.

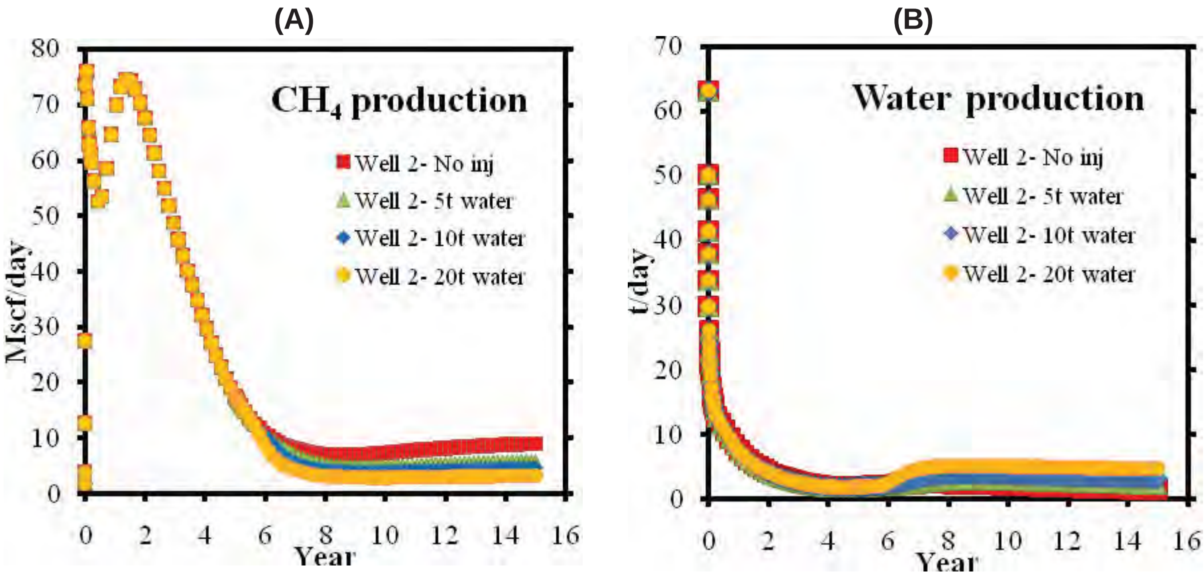


Figure 5.16. Results for water injection scenarios at the Ruawaro location with 80 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, and (B) water from well 2.

The water front at all injection rates reaches well 2 after approximately 1 year and in all cases *decreases* the CH_4 production rates. Although this result was expected, as to produce gas initially the reservoir must be dewatered, it clearly highlights the need for any re-injection program to be outside of the drainage area which may include the geological units directly above the coal reservoir. The location of potential re-injection sites warrants further investigation.

5.4.2 160 acre well spacing

Results from the pure CO_2 gas injection scenarios into the Ruawaro location are presented in Figure 5.17. As previously displayed in Figure 5.11, CH_4 production rates are less than those for the 80-acre spacing by about 10 Mscf/day (280 m^3/day) at the peak of production. The peak production is also delayed by over a year as more water had to be removed from the coal.

A small enhancement in CH_4 production rates at well 2 can be recognised from around 8 years for the 10 and 20 tonne/day injection scenarios. Injection at a rate of 5 tonne/day is yet to influence well 2. Not surprisingly, as well 4 was uninfluenced in the 80 acre scenario, no influence from gas injection is identifiable at well 4 during the modelled timeframe. The 20 tonne/day injection scenario stopped at just over 12 years likely for the reasons discussed above. Breakthrough of CO_2 is still minimal for the 20 tonne/day injection scenario at the time of model termination, commencing around year 12 with the slight increase visible from year 8 more likely related to enhanced production.

The results from the scenarios of injected flue gases at the Ruawaro location with a well spacing of 160 acres are presented in Figure 5.18. At well 2 the onset of enhancement is only slightly later than that seen for the 80 acre scenarios above however, the peak of the enhanced CH_4 production rate, at around 115 Mscf/day as opposed to around 87 Mscf/day for the 80 acre scenario, as well as the position on the CH_4 production only curve, 40 Mscf/day compared to 15 Mscf/day, reveals the significant quantity CH_4 was still in the reservoir that had not yet been accessed by production wells on a 160 acre spacing. Onset of enhanced production in well 4 is delayed to year 6, 7 and 8 for 20, 10 and 5 tonne/day injection rates respectively.

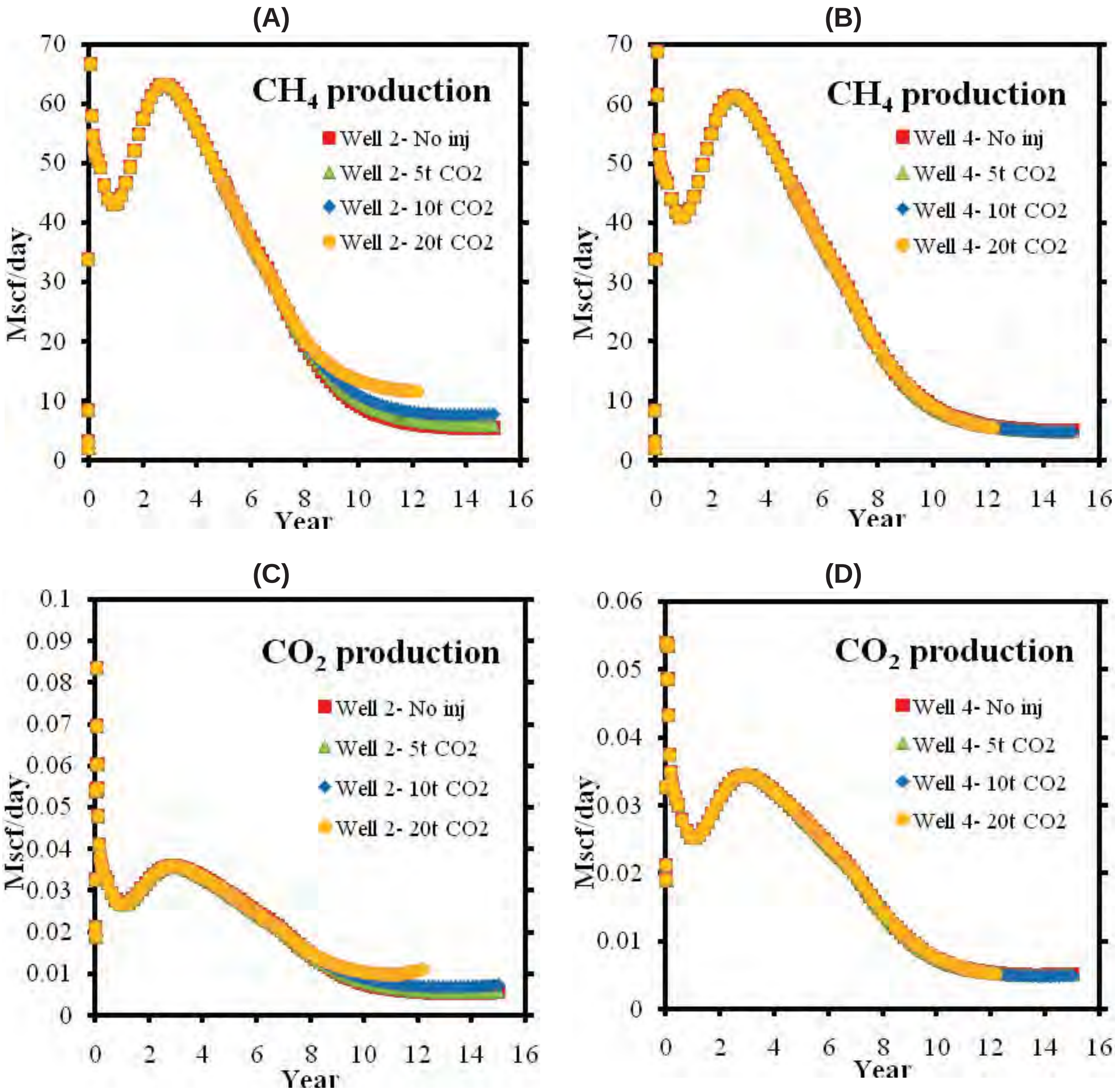


Figure 5.17. Results for CO_2 injection scenarios at the Ruawaro location with 160 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, and (D) CO_2 from well 4.

CO_2 breakthrough in well 2 is negligible for the 5 tonne/day scenario during the 15 year period and commences at around 8 years for 20 tonne/day and 10 years for the 10 tonne/day scenario. The small increase in CO_2 prior to these times is likely to result from enhanced production. Enhanced production is visible at well 4 and there is no evidence of CO_2 breakthrough as the production curves mimic those for CH_4.

While the onset of N_2 breakthrough in well 2 is only fractionally delayed compared to the 80 acre scenario, and the production rates by year 10 are the same, the breakthrough is not as abrupt. The production rates highlight how quickly N_2 moves through coal seam with little adsorption or dissolution. Increase in N_2 production in well 4 is again only slightly delayed compared to the 80 acre scenario with the bend in the curve, suggested earlier to be the influence of the high permeability fractures, being more pronounced. At 15 years N_2 production from well 4 is approximately half that seen in the 80 acre scenario.

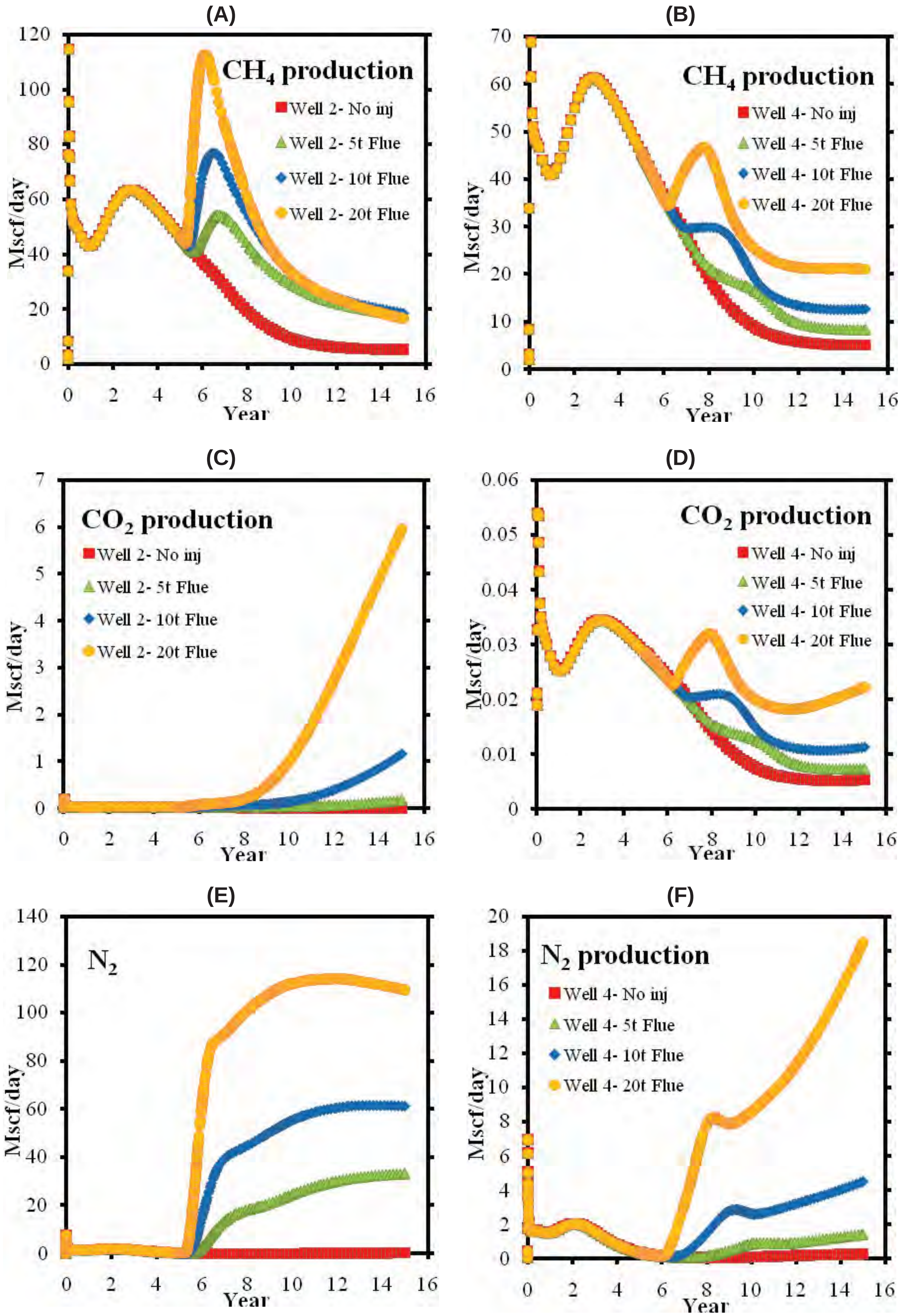


Figure 5.18. Results for flue gas injection scenarios at the Ruawaro location with 160 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) N_2 from well 2, and (F) N_2 from well 4.

5.4.3 320 acre well spacing

CO_2 injection scenario results for the Ruawaro location with 320 acre (1.3 km^2) spacing are presented in Figure 5.19. As no influence from gas injection was identified in either the 80 or 160 acre scenarios only results from well 2 have been displayed. Peak CH_4 production occurs around year 6 with a peak production rate of 50 Mscf/day, 2/3 that of the 80 acre peak production rate. After a period of slightly decreased production, 7.5 to 11 years (which possibly resulted from a pressure increase by water, flushed from areas of the reservoir distant to the production wells), the CH_4 production for the 20 tonne/day injection scenario shows a slight increase from enhancement. CO_2 production follows the same trend as that of CH_4 with no sign of breakthrough.

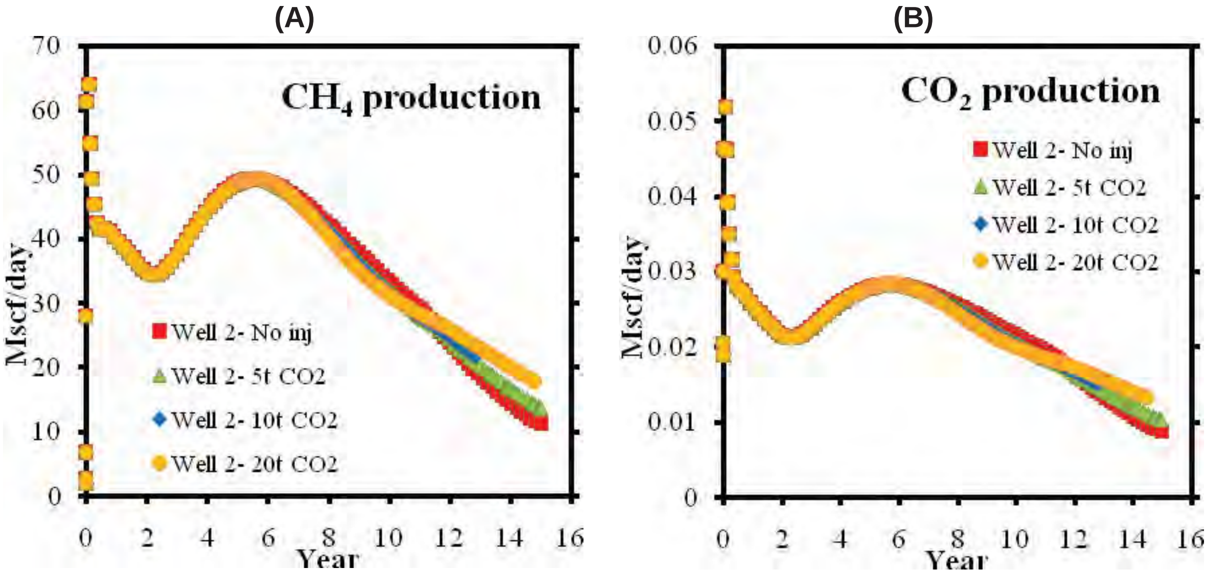
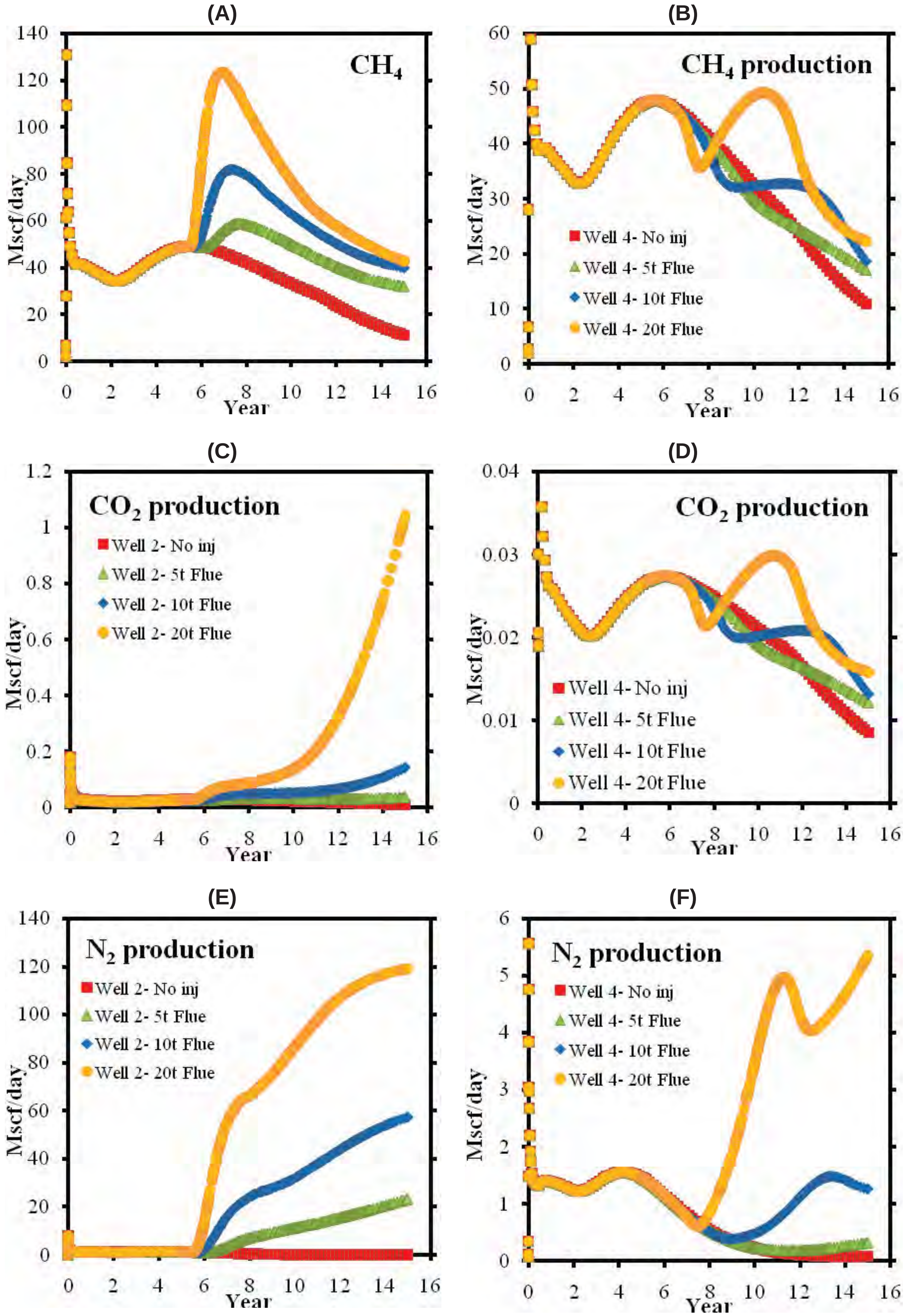


Figure 5.19. Results for CO_2 injection scenarios at the Ruawaro location with 320 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, and (B) CO_2 from well 2.

In spite of the increased reservoir size CH_4 production enhancement resulting from flue gas injection still commences in well 2 within a year of injection onset (Figure 5.20). The maximum production rate attained is greater than that for both the 80 and 160 acre scenario because of the large quantity of gas still remaining in the reservoir after the production only phase. After a period of decreased production rates, the enhancement is less significant in well 4 with onsets of 7.5, 8.5 and 10 years, for 20, 10 and 5 tonne/day injection rates.

Breakthrough of CO_2 occurs at 8 years for the 20 tonne/day injection scenario and at 12 years for the 10 tonne/day. There is no evidence of breakthrough in well 4. An increase in water production is noticeable in both wells.

The breakthrough of N_2 at well 2 again occurs prior to year 6 in all scenarios with production rates the reaching the same as those seen in the 80 and 160 acre scenarios by year 15. The slopes of the curves are much more gradual than those presented above. N_2 breakthrough also occurs at well 4 with onsets of 7.5, 8.5, and 12 years (the same times as CH_4 enhancements) for 20, 10 and 5 tonne/day scenarios reaching around a third of the production rates seen in the 160 acre scenarios.


(A)
CH4
Mscf/day
Year
(B)
CH4 production
Well 4- No inj
Well 4- 5t Flue
Well 4- 10t Flue
Well 4- 20t Flue
Mscf/day
Year
(C)
CO2 production
Well 2- No inj
Well 2- 5t Flue
Well 2- 10t Flue
Well 2- 20t Flue
Mscf/day
Year
(D)
CO2 production
Well 4- No inj
Well 4- 5t Flue
Well 4- 10t Flue
Well 4- 20t Flue
Mscf/day
Year
(E)
N2 production
Well 2- No inj
Well 2- 5t Flue
Well 2- 10t Flue
Well 2- 20t Flue
Mscf/day
Year
(F)
N2 production
Well 4- No inj
Well 4- 5t Flue
Well 4- 10t Flue
Well 4- 20t Flue
Mscf/day
Year

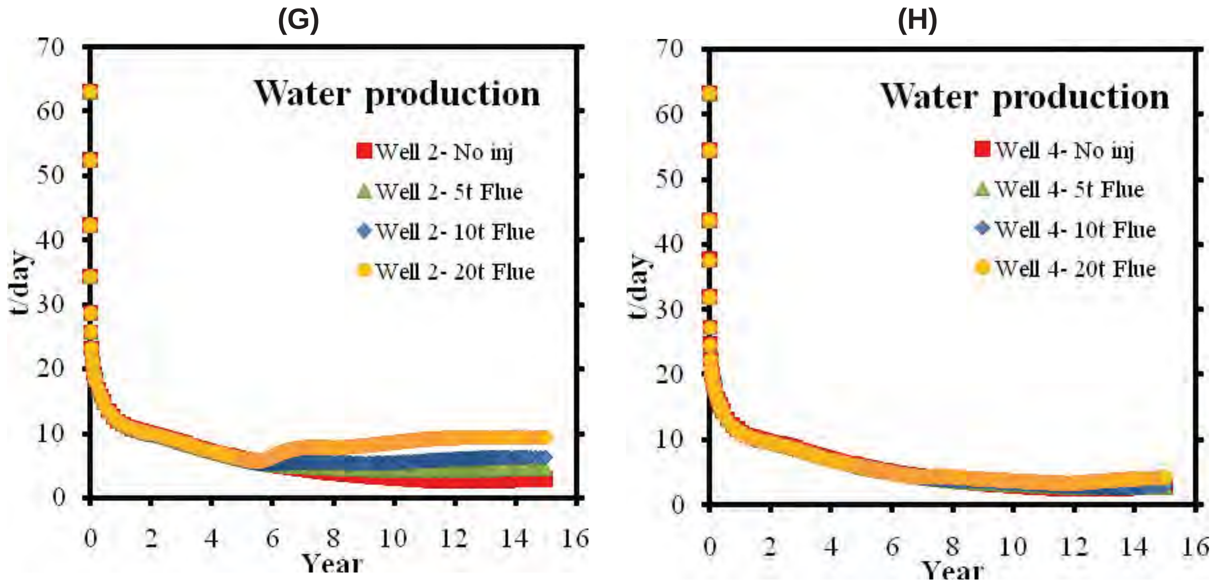


Figure 5.20. Results for flue gas injection scenarios at the Ruawaro location with 320 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) N_2 from well 2, (F) N_2 from well 4, (G) water from well 2, and (H) water from well 4.

5.5 ECBM SCENARIOS- MANGAPIKO

5.5.1 80 acre well spacing

The results for CO_2 injection into the Mangapiko location on an 80 acre (0.33 km^2) well spacing are presented in Figure 5.21. In spite of the considerably lower initial in situ gas content the effects of the greater permeability are immediately obvious. Unlike the Ruawaro location the gas production enhancement and breakthrough of CO_2 are both recognisable in well 4. The onset for enhancement in CH_4 production in well 2 for all injection rates is within the first year, with enhancement in well 4 commencing within the second year. The size of the enhancement of CH_4 production is also considerably greater than that seen at Ruawaro. All gas production curves show a pronounced decline peak correlating to a sharp spike in water production flushed ahead of the injected gas front.

Breakthrough of CO_2 occurs much earlier than in the Ruawaro scenario, commencing at 7, 8 and 10 years for the 20, 10 and 5 tonne/day injection rates respectively. The production rates incline steeply and quickly reach rates equal to the production rates of CH_4. At the end of the 15 years CO_2 production rates in well 4 were still minimal.

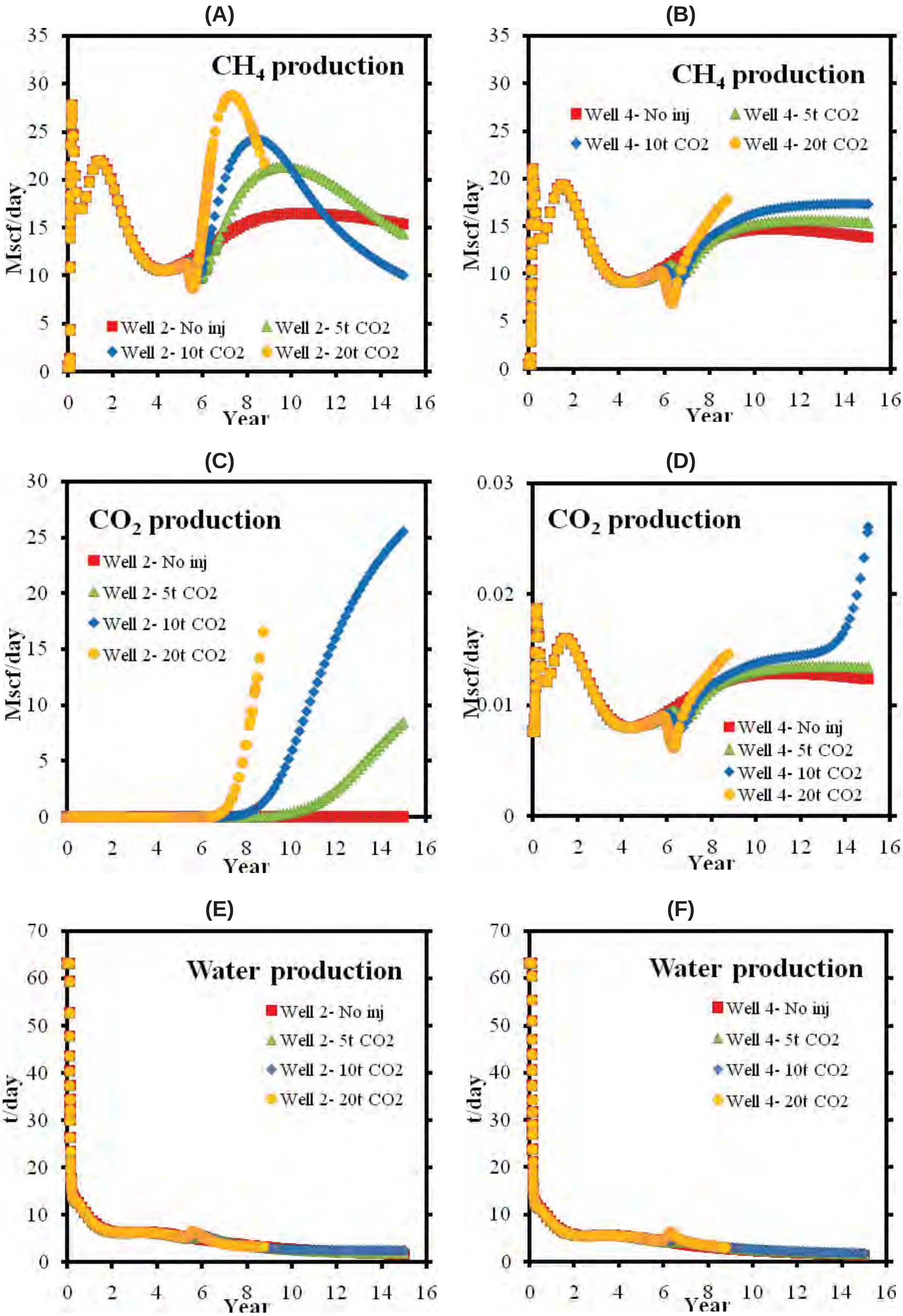
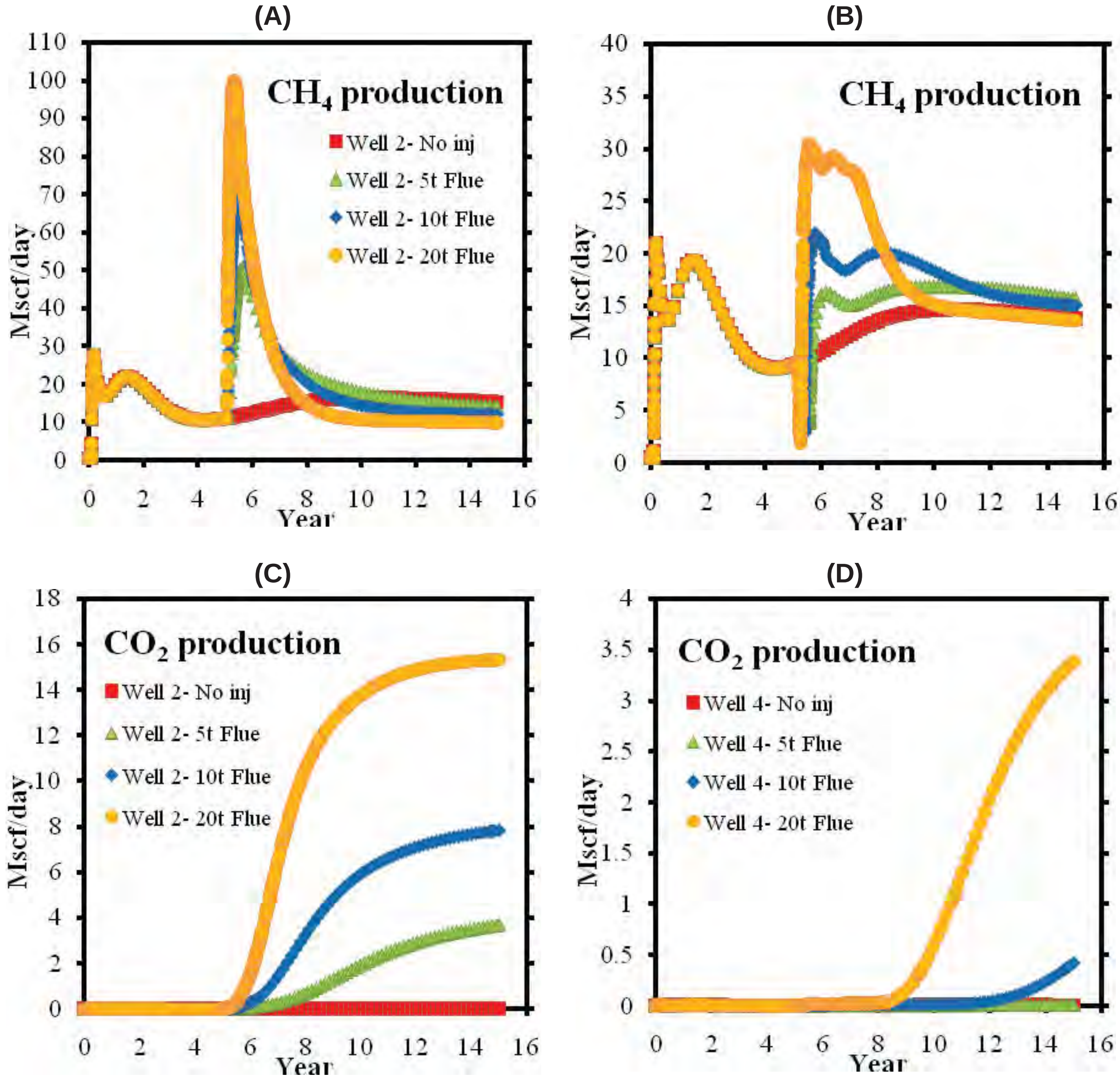


Figure 5.21. Results for CO_2 injection scenarios at the Mangapiko location with 80 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) water from well 2, and (F) water from well 4.

Flue gas injection scenario results for the Mangapiko location are presented in Figure 5.22. The onset of CH_4 production enhancement in both well 2 and well 4 is almost immediate, dramatically increasing to rates similar to those seen for the Ruawaro flue gas injection scenarios, however, unlike the Ruawaro scenario where production rates continue to be greater than the production only scenario rates (in red), production rates at Mangapiko drop back to being the same as, or even less than, production only rates within 3-4 years. This is because of the lower in situ gas contents at the Mangapiko location.



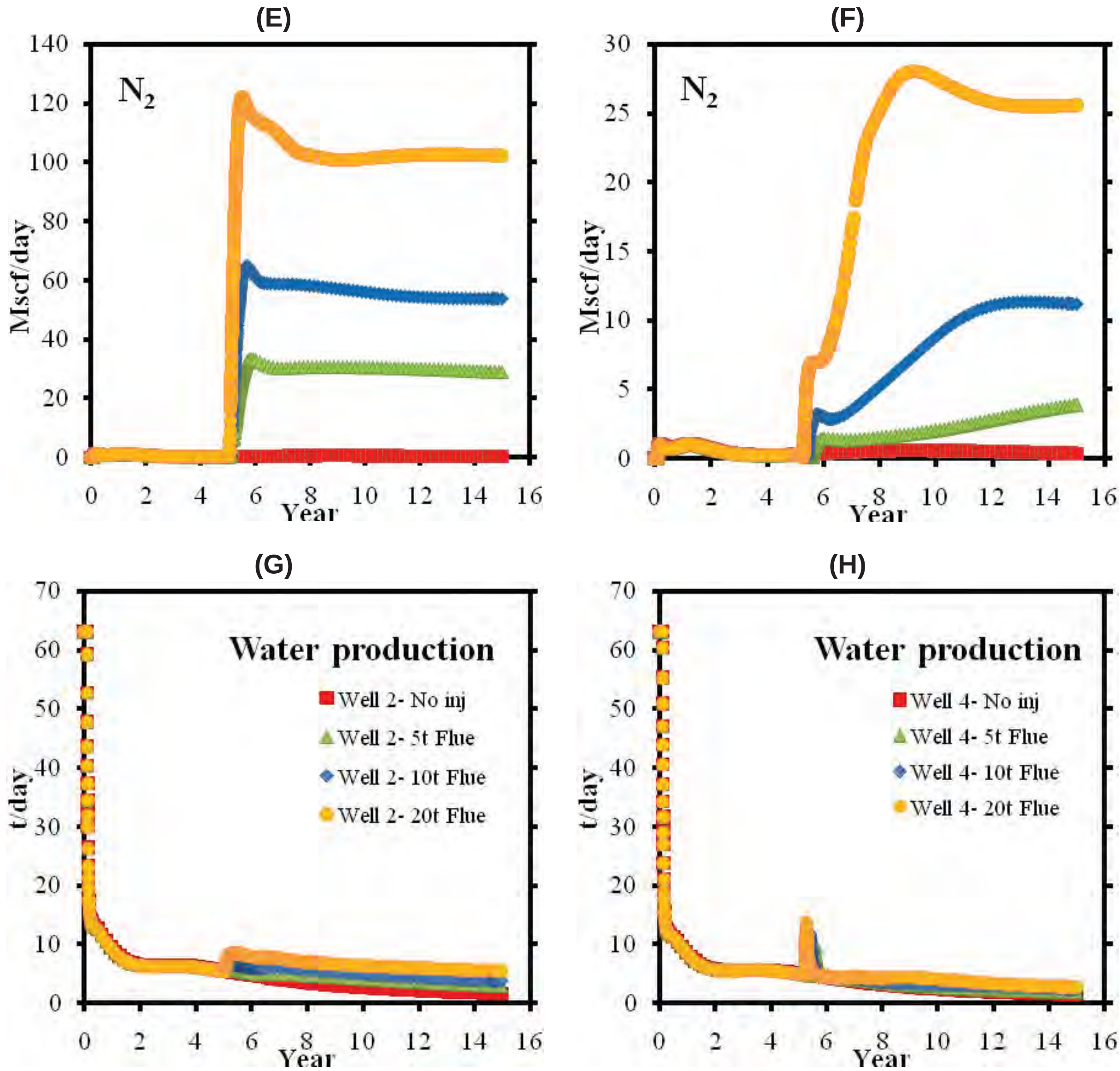


Figure 5.22. Results for flue gas injection scenarios at the Mangapiko location with 80 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) N_2 from well 2, (F) N_2 from well 4, (G) water from well 2, and (H) water from well 4.

Breakthrough of CO_2 occurs in well 2 within the first year regardless of injection rate, with CO_2 breakthrough in well 4 occurring in year 8 for 20 tonne/day injection and year 12 for the 10 tonne/day scenario. The breakthrough of N_2 was immediate in both wells with rates similar to those seen for the Ruawaro location, although the inclines of production rates at well 4 are steeper.

5.5.2 160 acre well spacing

Results for CO_2 injection into the Mangapiko location with 160 acre (0.65 km^2) well spacing are presented in Figure 5.23. The onset of enhanced production occurs for all scenarios prior to year 7. While the flush of water decreases the production rates from all injection scenarios at well 4 for at least a year, only the 20 tonne/day scenario shows production enhancement, beginning in year 8.

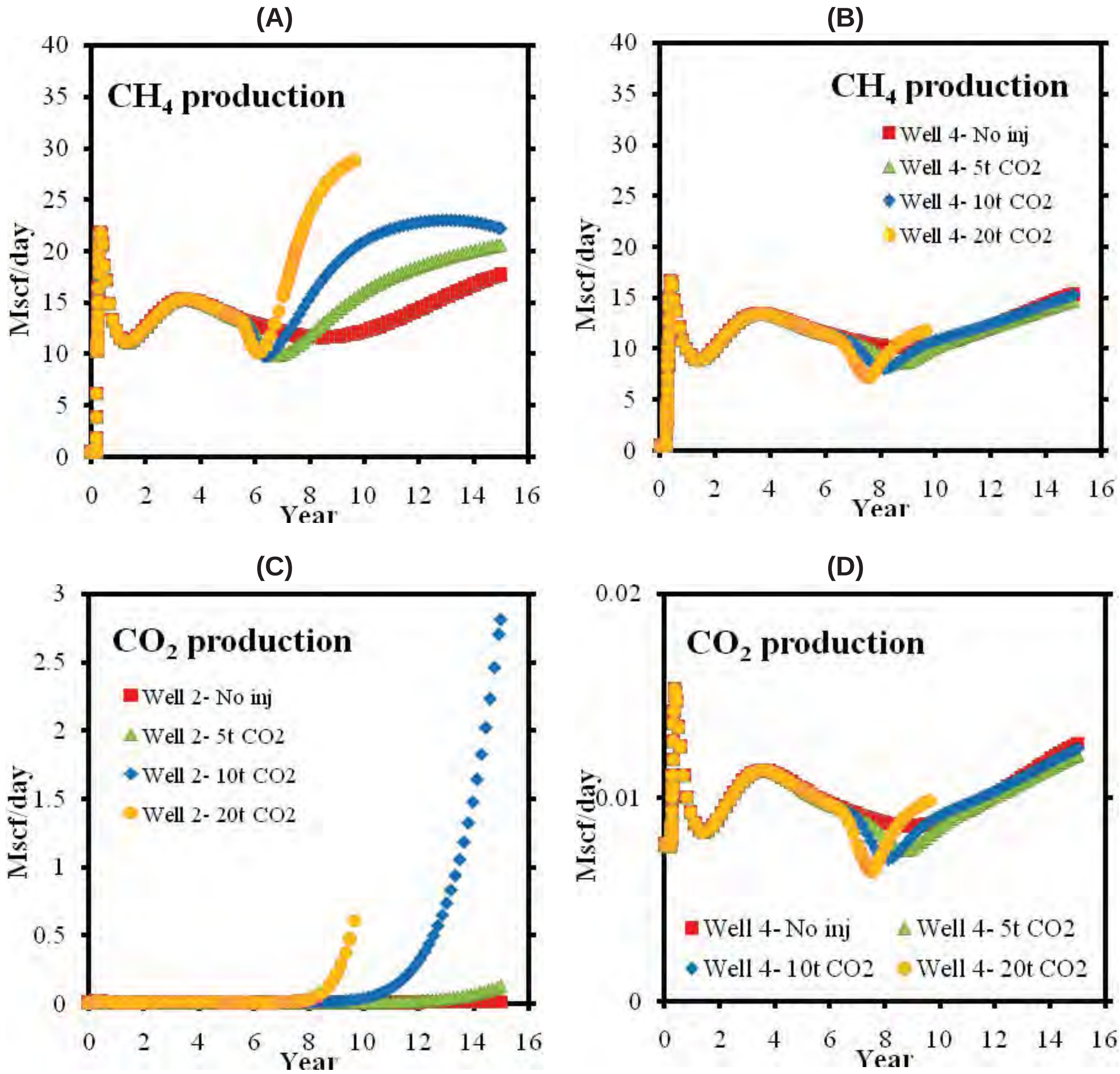


Figure 5.23. Results for CO_2 injection scenarios at the Mangapiko location with 160 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, and (D) CO_2 from well 4.

CO_2 breakthrough in well 2 is later than that seen for the 80 acre scenario commencing at years 8, 10 and 13 for the 20, 10 and 5 tonne/day injection scenarios respectively. It is possible that CO_2 breakthrough is also starting in well 4 during year 8 although at the time of model cessation was yet to reach a significant production rate.

Figure 5.24 presents the results for flue gas injection into the Mangapiko location with a well spacing of 160 acres. Onset of CH_4 production enhancement is still immediate in well 2 and commences between 5.5 and 6.5 years in well 4. The maximum CH_4 production rate in well 2 again reaches rates as high as those seen for the Ruawaro location but drops below the production only scenario line within 7 years.

The onset of CO_2 breakthrough in well 2 is earlier than that seen for the 160 acre Ruawaro scenario, starting 5.5, 6.5 and 8.5 for 20, 10 and 5 tonne/day injection scenarios respectively. Breakthrough of CO_2 at well 4 only occurs for the 20 tonne/day injection scenario commencing towards the end of year 11. N_2 breakthrough is again almost immediate in well 2 and commences prior to 6.5 years in well 4. As recognised in the Ruawaro location scenarios, N_2 rates increase to the same as those seen with an 80 acre well spacing however the incline in production rates from well 4 are more gradual.

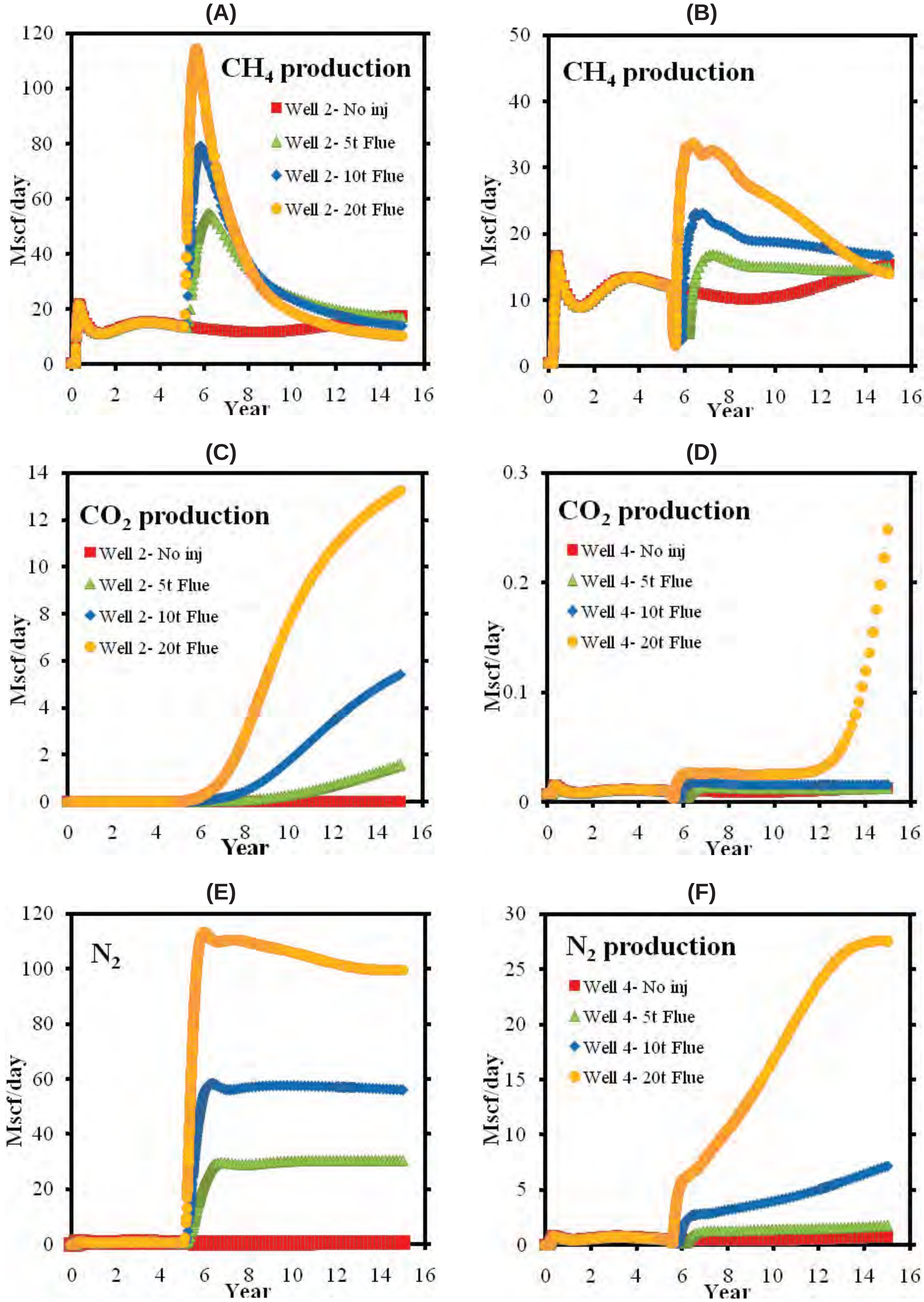


Figure 5.24. Results for flue gas injection scenarios at the Mangapiko location with 160 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) N_2 from well 2, and (F) N_2 from well 4.

5.5.3 320 acre well spacing

Results for the CO_2 injection scenarios into the 320 acre (1.3 km^2) Mangapiko scenario are presented in Figure 5.25. As no production enhancements or CO_2 breakthrough was evident in well 4 only results for well 2 are shown below. The production rates from well 4 did show the decline in production rates as seen for the 80 and 160 acre scenarios however these periods of decreased production lasted for several years. While this scenario may be good for CO_2 sequestration it is unlikely to be an economic CBM venture because of the low CH_4 production rates and minimal production enhancement. The 10 tonne/day injection scenario does show the beginning of CO_2 breakthrough at the end of the modelled timeframe however the rate is still very low.

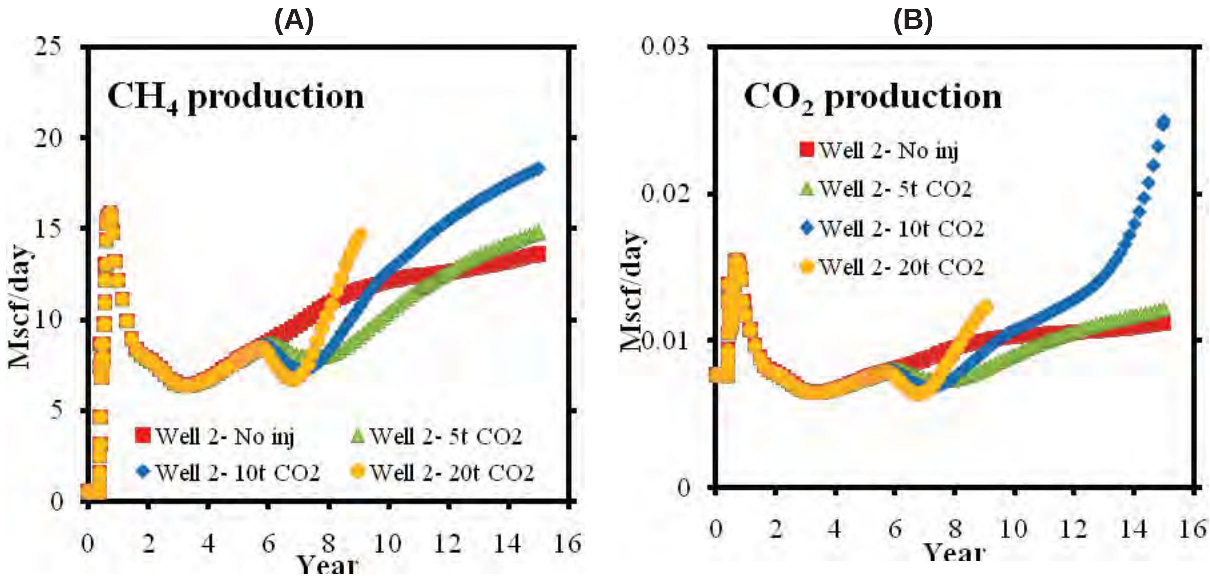


Figure 5.25. Results for CO_2 injection scenarios at the Mangapiko location with 320 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, and (B) CO_2 from well 2.

Figure 5.26 presents the results for flue gas injection into the Mangapiko location with a well spacing of 320 acres. Again the onset of CH_4 production enhancement is virtually immediate in well 2 and in well 4 commences between 6.5 and 8 years. The maximum CH_4 production rate in well 2 still reaches rates as high as those seen for the Ruawaro location however, unlike the 80 and 160 acre scenarios, does not drop below the production only rate within the 15 year period.

The onset of CO_2 breakthrough in well 2 is only slightly delayed from that seen for the 160 acre scenario although rates are lower. While enhanced production in well 4 is still significant at this spacing, breakthrough of CO_2 is yet to occur with CO_2 rates following those for CH_4. N_2 breakthrough is still fast and dramatic in well 2, while breakthrough in well 4 starts between 6.5 and 7.5 years but does not reach the rates seen in the 80 and 160 scenarios. The rates are however double those for the Ruawaro 320 acre scenario.

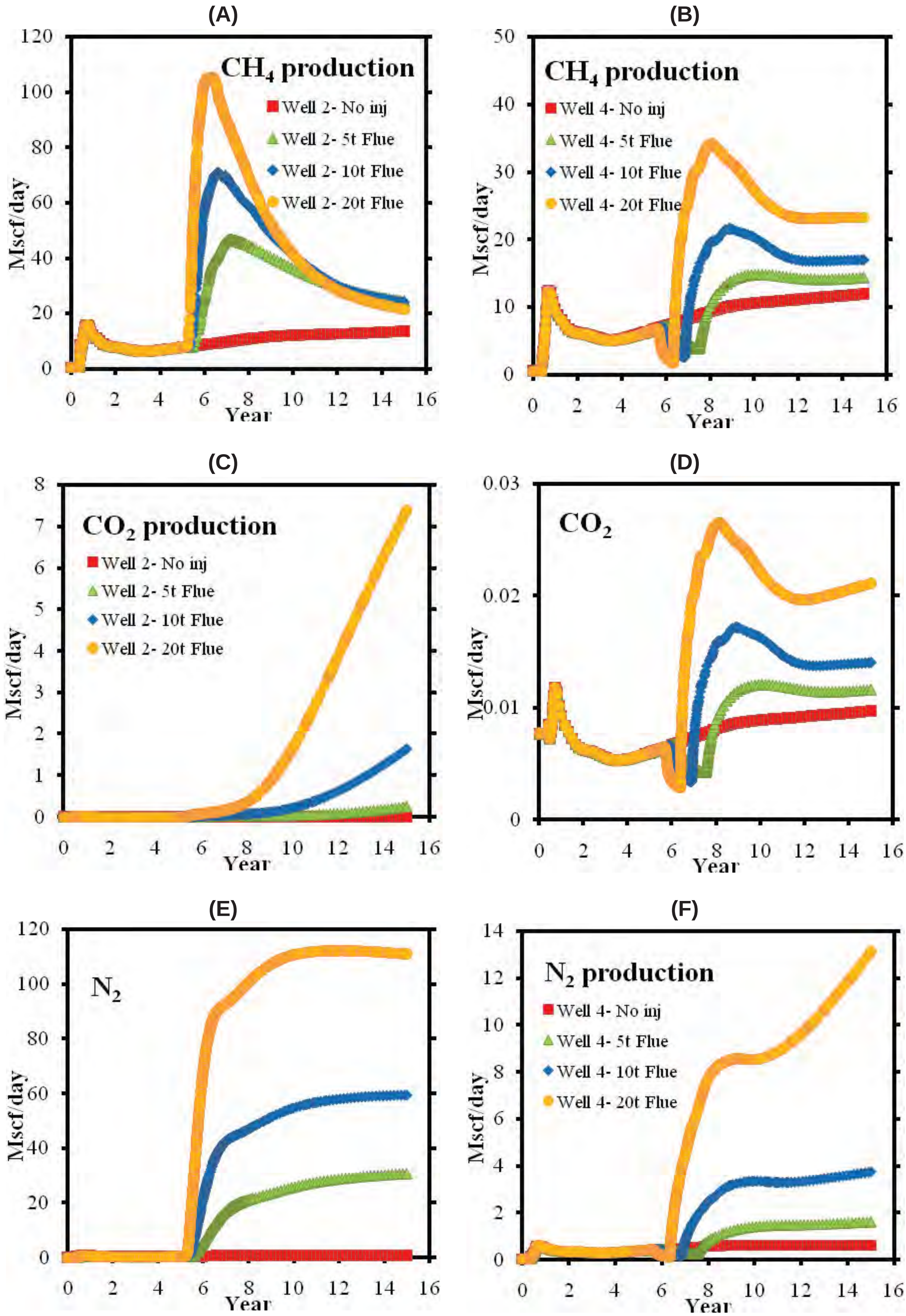


Figure 5.26. Results for flue gas injection scenarios at the Mangapiko location with 320 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) N_2 from well 2, and (F) N_2 from well 4.

5.6 ECBM SCENARIOS- OHINEWAI

5.6.1 80 acre well spacing

The results for the CO_2 injection scenarios for the Ohinewai location are presented in Figure 5.27 and for flue scenarios in Figure 5.28.

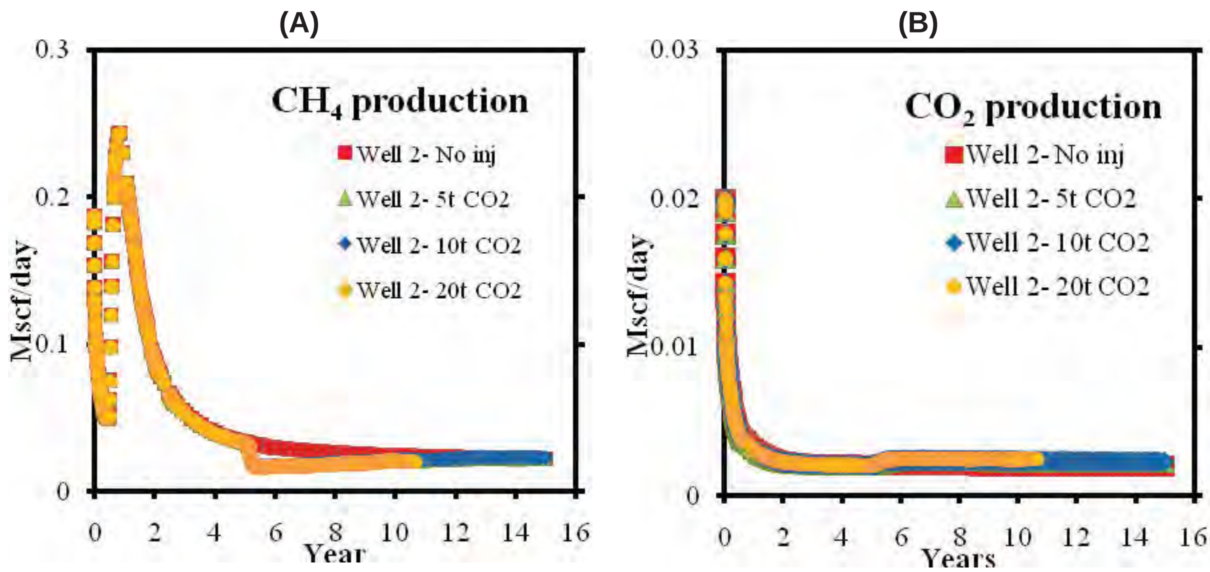
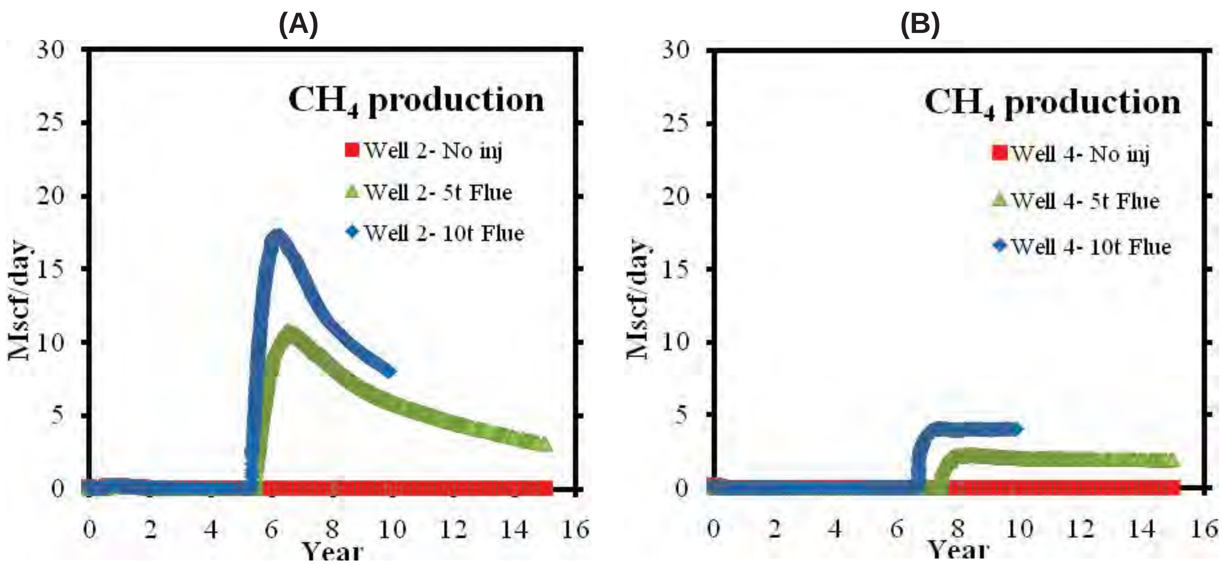


Figure 5.27. Results for CO_2 injection scenarios at the Ohinewai location with 80 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, and (B) CO_2 from well 2.



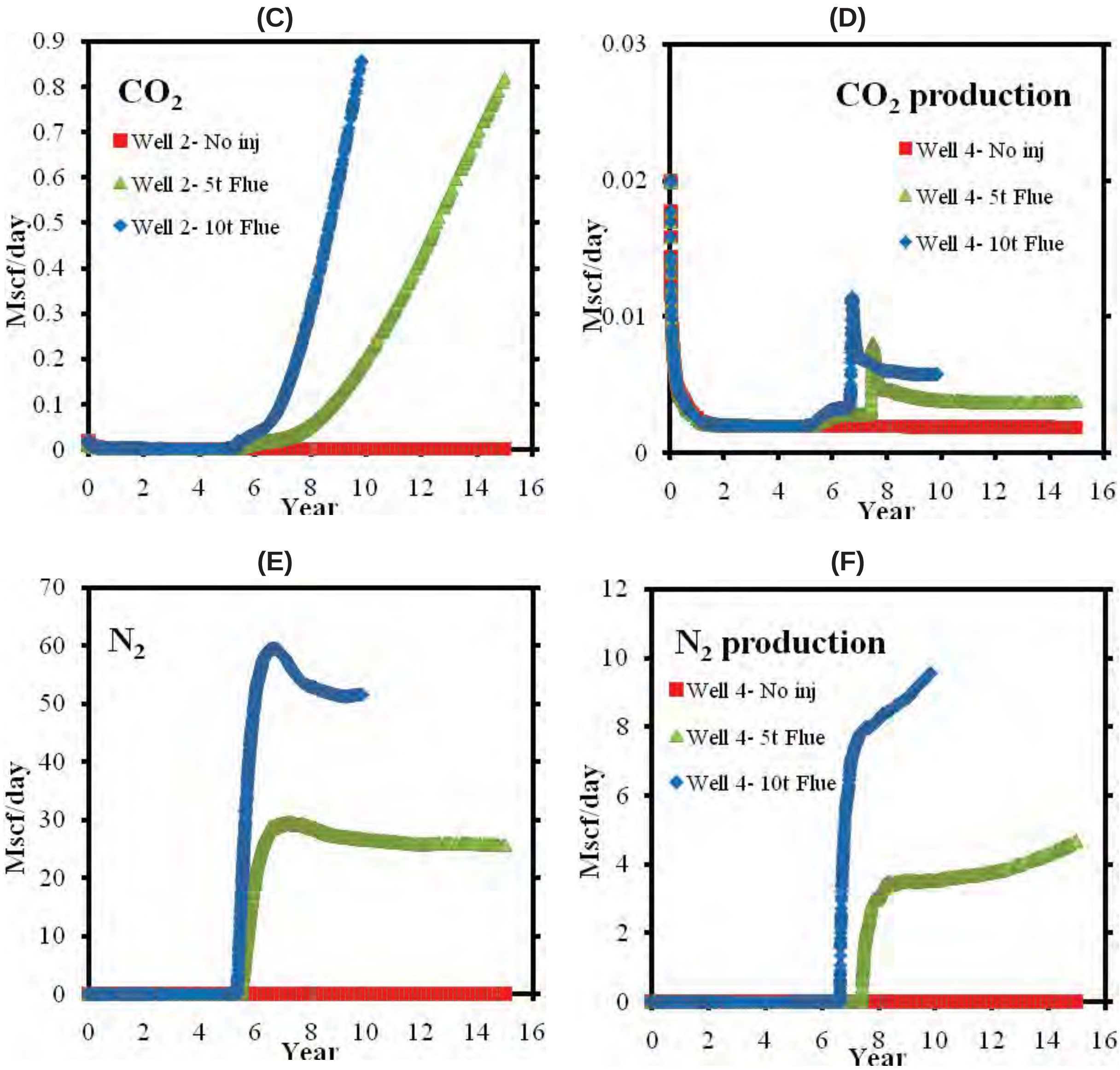


Figure 5.28. Results for flue gas injection scenarios at the Ohinewai location with 80 acre well spacing. Production rates are shown for: (A) CH_4 from well 2, (B) CH_4 from well 4, (C) CO_2 from well 2, (D) CO_2 from well 4, (E) N_2 from well 2, and (F) N_2 from well 4.

Despite having the same permeability as the Ruawaro location, no CH_4 production enhancement or CO_2 breakthrough is visible in well 2 for the CO_2 injection scenario. In the flue gas injection scenarios some breakthrough of CO_2 and N_2 does occur in both wells however the quantities are nowhere near those seen in the Ruawaro and Mangapiko scenarios. There is a substantially thicker coal seam in the Ohinewai model however the adsorption capacities are not that dissimilar to those of the other locations. Larger well spacing scenarios were not conducted for the Ohinewai location as it was thought the injected gas was escaping. This possibility will be explored in section 6.8.

5.7 WELLBORE PRESSURE AND TEMPERATURE

Bottom hole pressures from the injector wells for the Ruawaro, Mangapiko and Ohinewai locations (80 acre scenarios) are presented in Figure 5.29 and for temperature in Figure 5.30. In this study, wellbore effects such as gravitational, friction and acceleration are not taken into consideration and will need to be modelled separately at a later date.

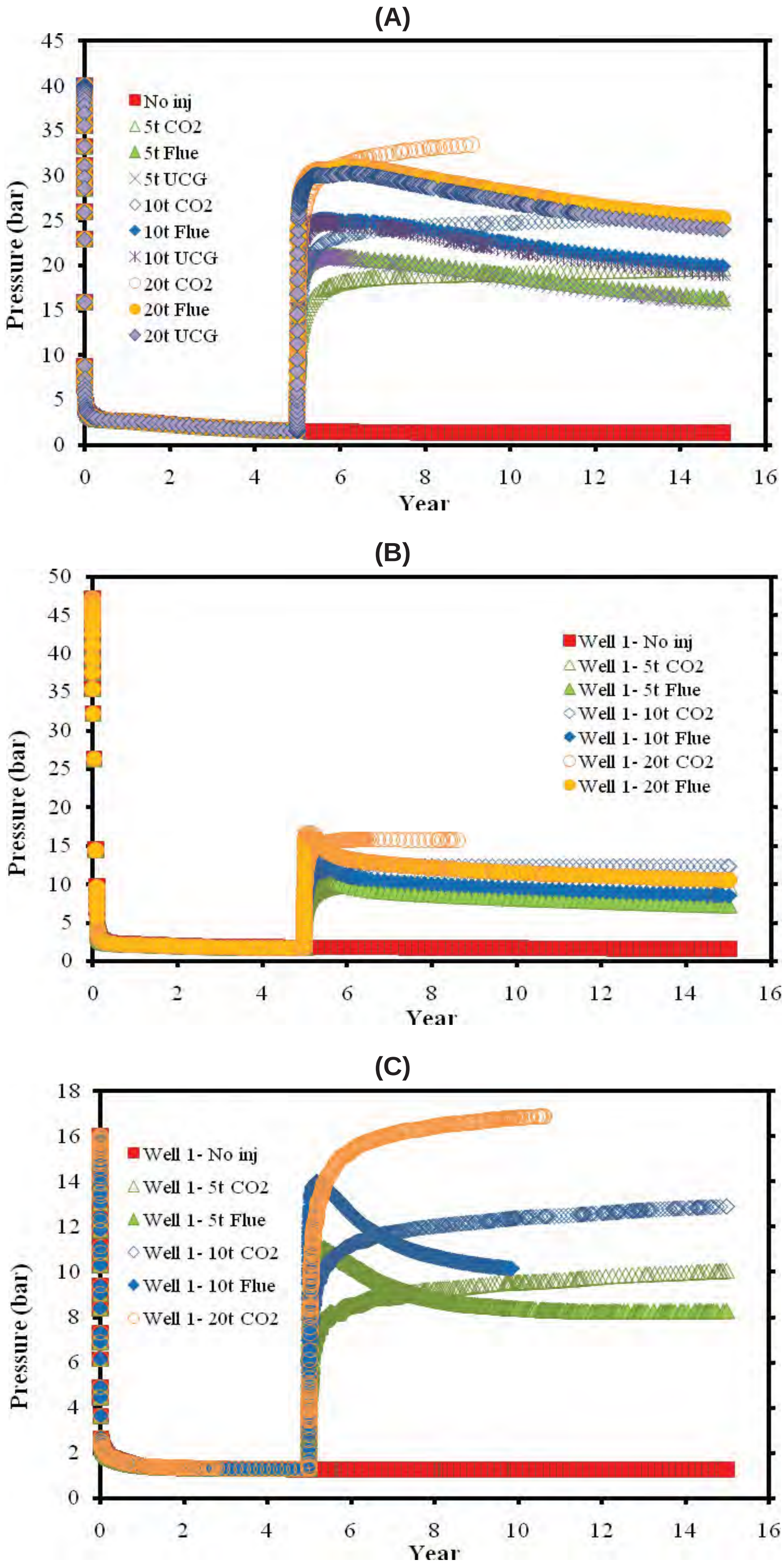


Figure 5.29. Bottom hole pressures for the injector wells at the (A) Ruawaro location, (B) Mangapiko location, and (C) Ohinewai location.

Both production from and injection into the well block creates immediate changes in well block pressure. As to be expected, the larger the injected volume, then the greater is the increase in well bore pressure. After this sharp initial increase in pressure, the continued injection of pure CO_2 results in a small but steady increase in well bore pressure as the CO_2 adsorbs into the coal close to the well block. In contrast, while injection of flue gas in the same volume creates a higher initial pressure, well block pressure steadily decreases with time as the injected gas more successfully moves away from the well block and into the reservoir. The injection of UCG gases into the Ruawaro scenario produces pressures slightly lower than that for flue gas (due to the high adsorption capacity for H_2S) however the trend of pressure decrease with time is the same.

Although the initial increase in well block pressure is dramatic, for the Ruawaro and Mangapiko locations injection pressures do not exceed the initial reservoir pressure. This is not true for the shallower Ohinewai location. Injection pressures for the Mangapiko and Ohinewai locations only reach half of the pressures seen for the Ruawaro location. At the Mangapiko location this results from the much greater permeability present in the coal seam allowing easier movement of injected gases far into the reservoir while in the Ohinewai location, which has the same initial permeability as Ruawaro, the coal reservoir is much thicker, there is much less overlying hydrostatic pressure (shallower) and as mentioned previously the injected gases can escapes to the surface.

The well bore also undergoes instantaneous temperature changes in response to gas injection. The injection of pure CO_2 decreases the temperature initially as the injected gas is at atmospheric temperature (lower than reservoir temperature). Possibly due to the lower pressures reached and the greater permeability at the Mangapiko location, temperatures remain lower than those for injection of CO_2 at the Ruawaro location. Although also injected at atmospheric temperature, flue gas injection creates much higher temperatures than CO_2 injection with UCG gases causing even higher well bore temperatures, because of the higher percentage of N_2 and the inclusion of H_2S. As the injection of flue gas caused similar temperatures in both the Ruawaro and Mangapiko locations, unlike the temperatures seen for CO_2, possibly it is the quantity of injected N_2 that has the greater control on temperature. Temperatures reached at the Ohinewai location are lower than for the other sites, likely because of the lower pressures involved and the greater volume (thickness) of coal into which gas can adsorb.

The step like increases in the temperature profiles were found to correlate to step like decreases in the liquid density of the well block (Figure 5.31). This occurs as the gas dissolves into the water.

Knowledge of potential injection pressures and the resulting temperatures is important for the design of field infrastructure. Areas where injection pressures are greater will require more powerful compressors which are of course much more expensive. Any down hole monitoring equipment in the injection well will also need to be rated for temperatures greater than those likely to be reached during the injection phases.

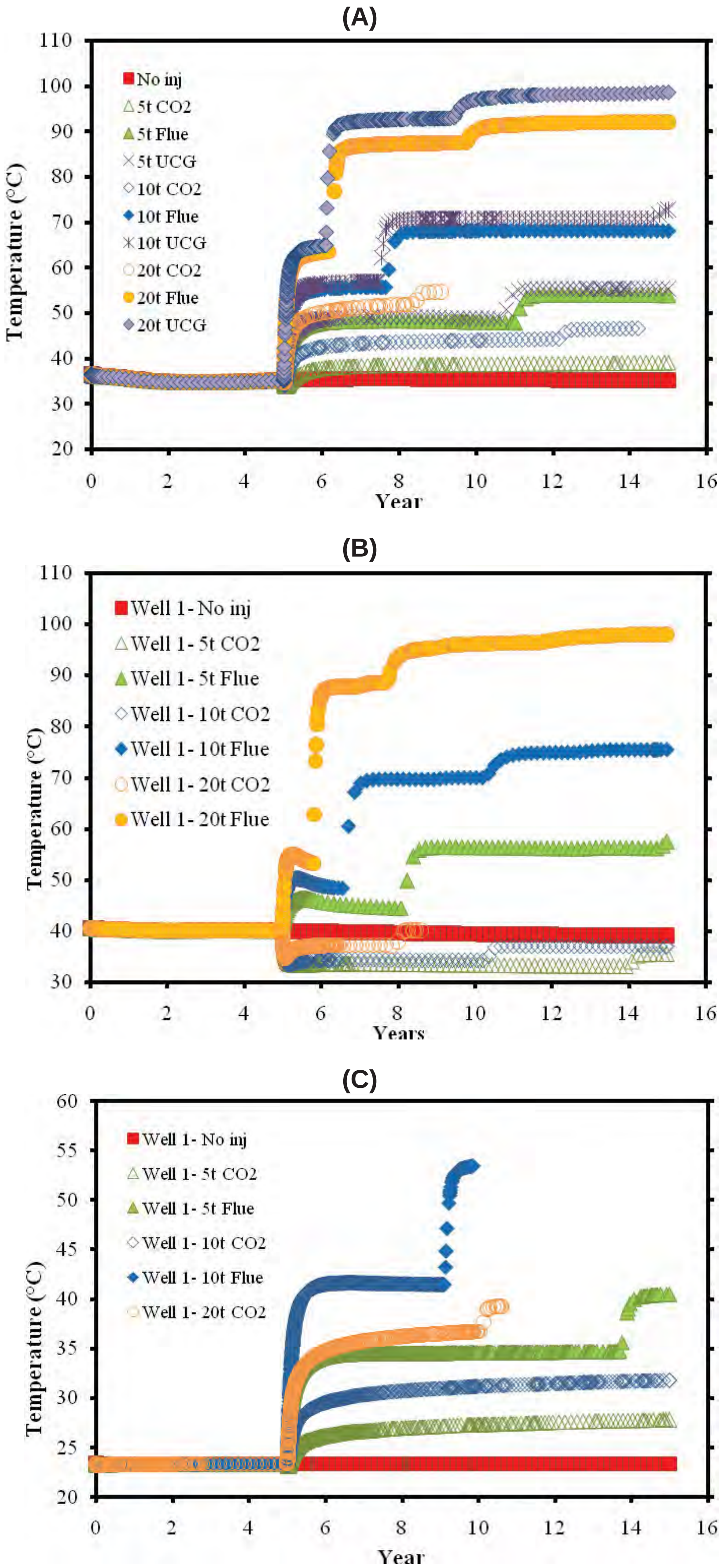


Figure 5.30. Bottom hole temperatures for the injector wells at the (A) Ruawaro location, (B) Mangapiko location, and (C) Ohinewai location.

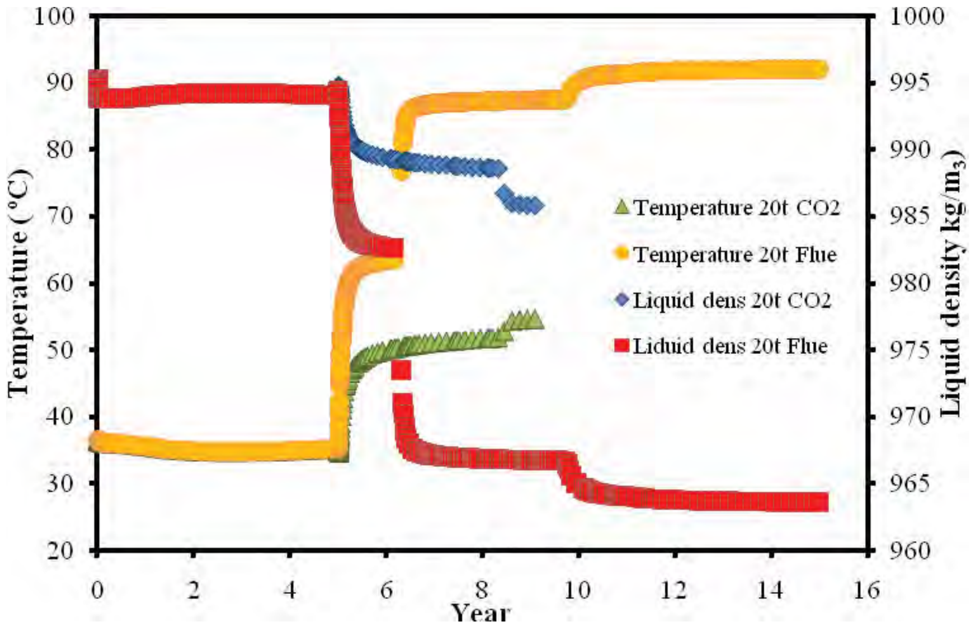


Figure 5.31. Plot of temperature versus liquid density for the injector well block at the Ruawaro location.

5.8 MONITORING FOR LEAKAGE OF INJECTED GASES

No leakage of injected gas was identified for either the Ruawaro or Mangapiko locations during the 15 year period (Figure 5.32). Closer investigation of the models found no evidence of gas penetrating above the WCM (layer 7) during the modelled time frame. Modelling of extended time periods, e.g. up to 1000 years, after the injection period was not completed at the time of this report but it is highly recommended that this be followed up in future work.

Although in very small quantities, flue gas escaped to the surface in all of the modelled scenarios for the Ohinewai location and was identified as high as layer 3 (the WCM), just below the permeable Tauranga Group, for the pure CO_2 injection scenarios. Monitoring results for the 5 tonne/day and 10 tonne/day scenarios are presented in Figure 5.33 and Figure 5.34. Surface manifestation started directly above the injector well and spread out in the direction of the subsurface fracture set (Figure 5.35), beginning a year after the start of injection 10 tonne/day scenario and after 2 years for the 5 tonne/day scenario.

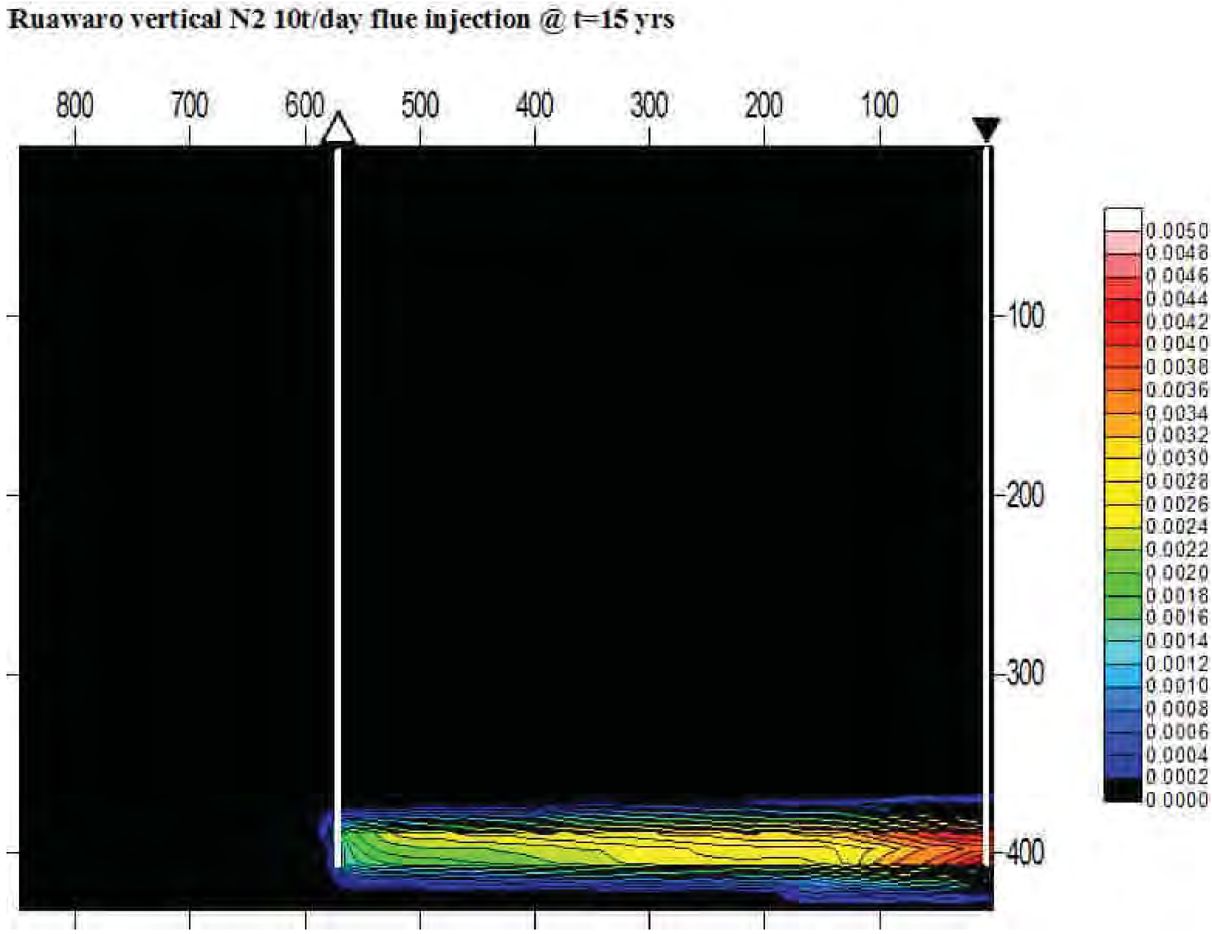


Figure 5.32. Cross-section at the Ruawaro location from the injector well (▼) to well 2 (Δ) showing mass fraction of N_2. 10 tonne/day flue gas injection scenario.

Leakage to the surface is likely a result of a lack of thick, low permeability sealing units, low initial reservoir pressures due to the shallow depth and injection pressures close or exceeding initial reservoir pressures. This result is not overly surprising as the very low initial in situ gas contents were likely because of gas escape. Clearly the Ohinewai location is unsuitable for sequestration.

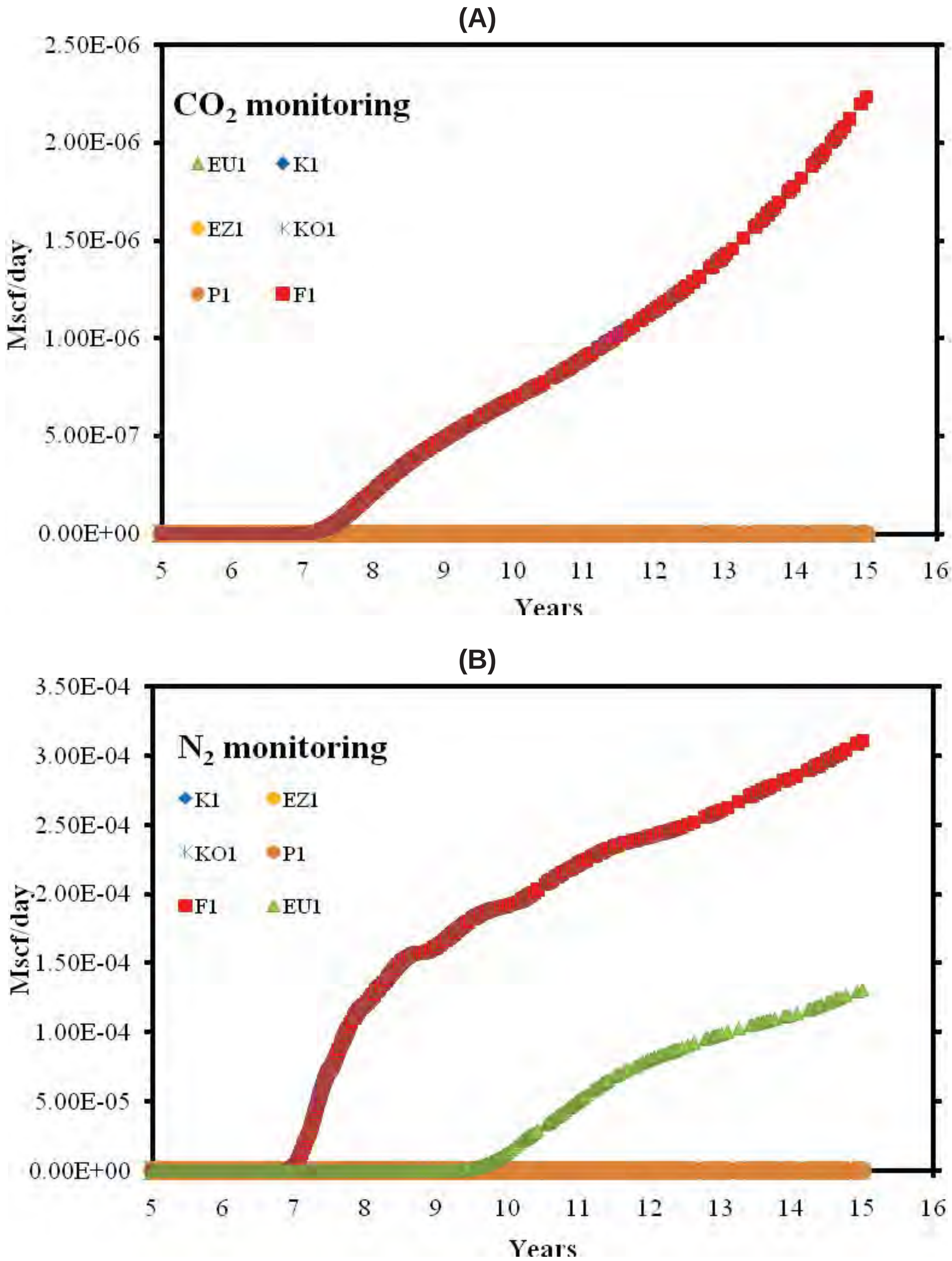


Figure 5.33. Results from surface monitoring wells in the 5 tonne/day flue gas injection scenario for (A) CO_2 and (B) N_2.

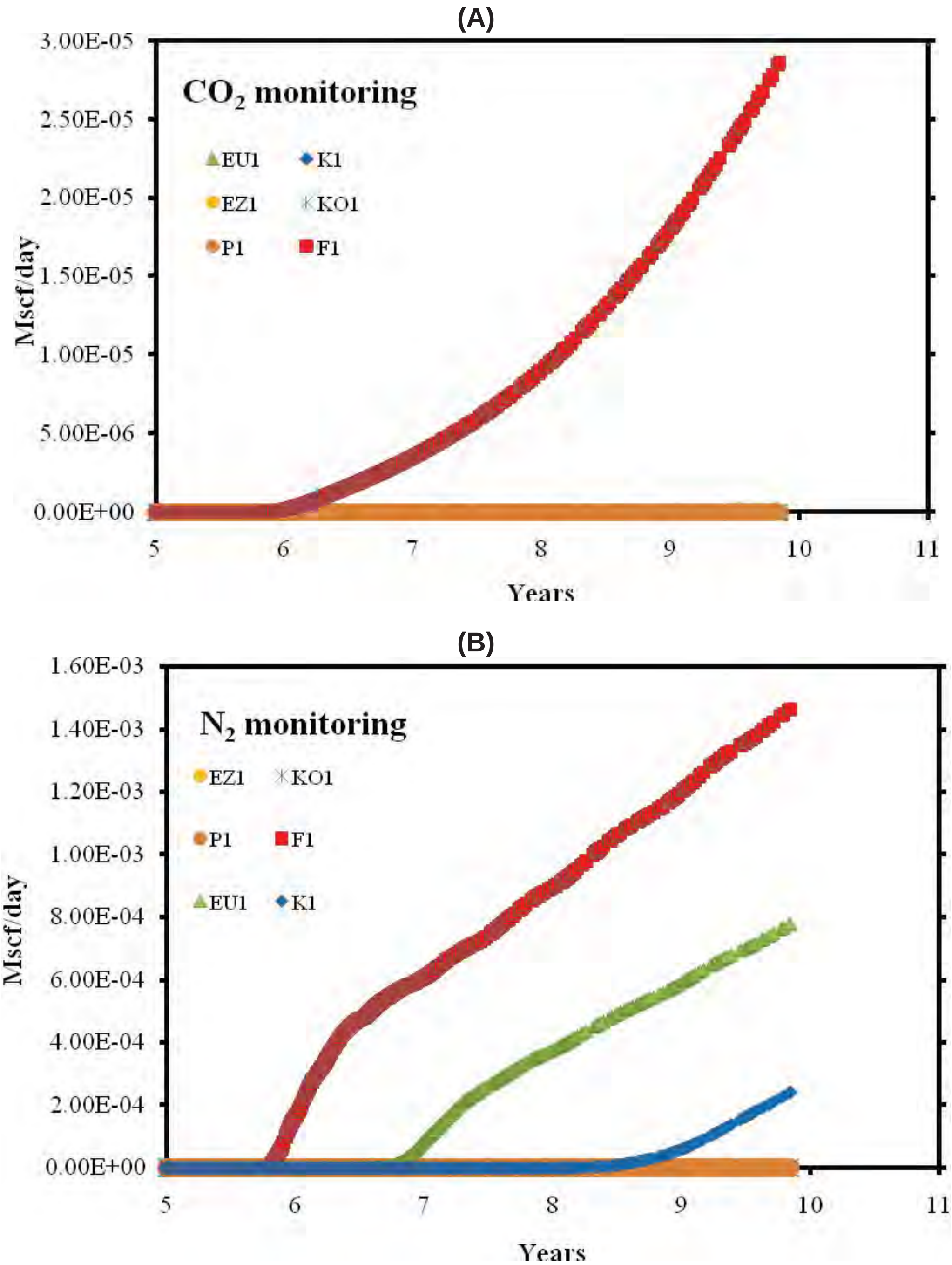


Figure 5.34. Results from surface monitoring wells in the 10 tonne/day flue gas injection scenario for (A) CO_2 and (B) N_2.

(A)

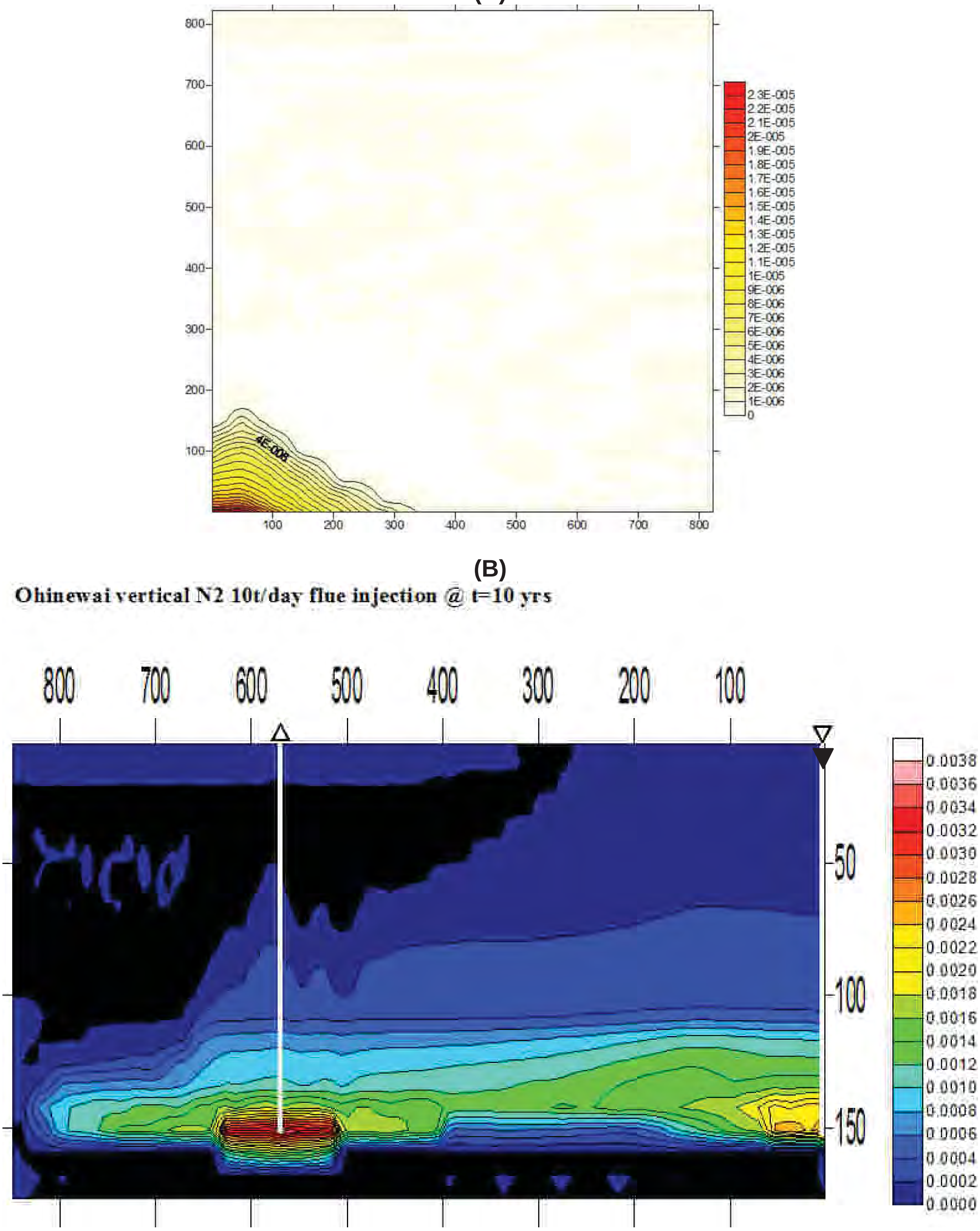


Figure 5.35. (A) Surface manifestations at the Ohinewai location for the 10 tonne/day injection scenario showing the mass fraction of N_2 and (B) cross-section from the injector well (▼) to well 2 (Δ) showing the mass fraction of N_2.

6.0 CONCLUSIONS

CO_2 sequestration and ECBM scenarios were conducted for three locations within the Waikato coalfields, Ruawaro, Mangapiko and Ohinewai, using the TOUGH2.2 reservoir simulator. The results clearly identified the Ruawaro and Mangapiko locations as being suitable for further investigation. In contrast, the Ohinewai location can be excluded as, aside from being unsuitable for CBM production because of very low gas content, the models showed leakage of injected gases to the surface. This leakage is likely a function of the shallow reservoir depth in this location, resulting in a much lower hydrostatic pressure, and the absence of the thick low permeability units (cap formations) present in the other locations.

For CBM the production scenarios the Ruawaro location would clearly be the favoured site because of the considerably greater gas content. For all scenarios stimulated wells perform substantially better than unenhanced wellbores, with the Ruawaro scenario peak production rate of the stimulated wells being double that for the unenhanced wells. An increase in well spacing increases the time until peak production is reached, with the peak production rate being lower than for closer spaced wells but the peak rate is maintained for a longer period of time. Optimal well spacing will be decided by long term field development plans, land access and economics. The greater permeability at the Mangapiko location resulted in faster and more successful drainage of the reservoir with both the Ruawaro and Mangapiko scenarios showing an increase in permeability with production time resulting from depressurisation of the reservoir and matrix shrinkage from gas desorption.

CO_2 sequestration appeared to be more successful at the Ruawaro and Mangapiko sites. Where breakthrough occurred, it was earlier at the Mangapiko location than at the Ruawaro for all scenarios because of the higher permeability. As such, a larger well spacing maybe desirable at this location. For the Ruawaro scenarios CO_2 never reached the well furthest from the injection well (well 4) hence production gas quality may only be affected in the wells closest to the injector. The injection of CO_2 had little enhancement on CH_4 production at either location. While injecting at rates of 5 and 10 tonne/day seems feasible, injecting at a rate of 20 tonne/day caused model failure in all scenarios. This likely occurred as the gas could not move away from the wellbore fast enough (a result of permeability reduction) which in field conditions probably results in a significant drop in injection rate.

Flue gas injection scenarios had significant enhancement on CH_4 production in all scenarios however breakthrough of N_2, the primary component of flue gas, is almost instantaneous in the closest well (well 2) and quickly reaches production rates similar to those seen for CH_4. CO_2 also breaks through faster in the flue gas scenarios than for pure CO_2 gas injection despite being in smaller quantities. This is because the presence of N_2 reduces the partial pressure of CO_2 allowing ease of movement and adsorption further from the wellbore. In the larger spaced Ruawaro scenarios, and the more permeable Mangapiko scenarios, the water flushed from the reservoir ahead of the injected gas front can have a short term negative effect on CH_4 production from well 4. The selected rate of injection and well spacing will depend on the requirements of the end user as well as the number of production wells online, producing relatively pure methane, available for blending gas quality. Injection of flue gases generated from UCG produced results very similar to those seen for the flue gases from gas fired generators, while the injection of water clearly showed that waste water re-injection wells need to be away from the drainage area of the coal seam, which may or may not be confined to the coal layer.

Wellbore pressure for all scenarios shows a dramatic increase when injection commences however, for the Ruawaro and Mangapiko locations, this pressure did not exceed initial reservoir pressure. After the initial increase, continued injection of CO_2 causes a small but steady increase in well block pressure while flue gas injection shows a steady decrease. Because of the greater permeability, injection pressures at Mangapiko reach only half those seen for the Ruawaro location. The wellbore temperature also undergoes instantaneous change with flue gas injection causing considerably higher temperatures than pure CO_2 injection. An understanding of potential wellbore pressures and temperatures will be essential in field infrastructure requirements.

Surface monitoring wells for dectecting injected gas leakage identified leakage in the Ohinewai scenarios deeming the location unsuitable for sequestration and ECBM. No leakage was identified for the Ruawaro and Mangapiko locations during the modelled time frame. Modelling of extended time frames was not completed in time for this report however this is extremely important and should be considered in future work.

Other aspects that should be followed up in future work include:

- Permeability analyses for overlying strata
- Intermittent injection of CO_2 and flue gases
- Wellbore effects
- Water re-injection scenarios
- Effects of faults in the reservoir
- Use of coupled models
- Potential of CBM regeneration by methanogenesis

7.0 ACKNOWLEDGEMENTS

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8.0 REFERENCES

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