



The Allison Unit CO₂-ECBM Pilot – A Reservoir and Economic Analysis

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ABSTRACT

In October, 2000, the U.S. Department of Energy, through contractor Advanced Resources International, launched a multi-year government-industry R&D collaboration called the Coal-Seq project. The Coal-Seq project investigated the feasibility of CO₂ sequestration in deep, unmineable coalseams by performing detailed reservoir studies of two enhanced coalbed methane (ECBM) recovery field projects in the San Juan basin. The two sites were the Allison Unit, operated by Burlington Resources, into which CO₂ was injected, and the Tiffany Unit, operating by BP America, into which N₂ was injected (the interest in understanding the N₂-ECBM process has important implications for CO₂ sequestration via flue-gas injection). The objectives of the field studies were to understand the reservoir mechanisms associated with CO₂ and N₂ injection into coalseams, demonstrate the effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate ECBM/sequestration economics. In support of these efforts, laboratory and theoretical studies were also performed to understand multi-component isotherm behavior, and coal permeability changes due to swelling with CO₂ injection. This paper presents the results of The Allison Unit study, in which a detailed reservoir characterization of the field was developed, the field history was matched using the COMET2 reservoir simulator, future field performance was forecast under various operating conditions, and an economic analysis performed.

INTRODUCTION

In October, 2000, the U.S. Department of Energy (DOE), through contractor Advanced Resources International (ARI), launched a multi-year government-industry R&D collaboration called the Coal-Seq project¹. The Coal-Seq project investigated the feasibility of CO₂ sequestration in deep, unmineable coalseams by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin. The two sites were the Allison Unit, operated by Burlington Resources, into which CO₂ was injected, and the Tiffany Unit, operated by BP America, into which N₂ was injected (the interest in understanding the N₂-ECBM process has important implications for CO₂ sequestration via flue-gas injection). The objectives of the field studies were to understand the reservoir mechanisms of CO₂ and N₂ injection into coalseams, demonstrate the effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate ECBM/sequestration economics. In support of these efforts, laboratory and theoretical studies were also performed to understand multi-component isotherm behavior, and coal permeability changes due to swelling with CO₂ injection. This paper presents the results of The Allison Unit study, in which a detailed reservoir characterization of the field was developed, the field history was matched using the COMET2 reservoir simulator, future field performance was forecast under various operating conditions, and an economic analysis performed.

SITE DESCRIPTION

The Allison Unit ECBM pilot is located in San Juan County, southern New Mexico, in close proximity to the border with Colorado (Figure 1). While the Unit consists of many wells, the pilot area for CO₂ injection consisted of 16 coalbed methane (CBM) producer wells, 4 CO₂ injectors, and one pressure observation well (POW #2). The study area well pattern is illustrated in Figure 2. At the center of the study area is a five-spot of CBM producers on nominal 320 acre spacing (wells 130, 114, 132 and 120 at the corners, and well 113 in the center), with the four CO₂ injectors roughly positioned on the sides of the five-spot between the corner producer wells (creating a nominal 160 acre spacing between injectors and producers). POW #2 is located on the eastern border of the central pattern, and the remaining CBM producers surround this central pattern.

The producing history for the study area is shown in Figure 3. The field originally began production in 1989, with CO₂ injection occurring between April, 1995 and August, 2001. Several points are worth making regarding the producing history:

- Upon commencement of the injection operations, the five producer wells in the central five-spot pattern were shut in. The purpose was to facilitate CH₄/CO₂ exchange in the reservoir. After about six months, CO₂ injection was suspended for about another six months, during which time the five shut-in producers were re-opened. These activities can be clearly identified in Figure 3; their impact on long-term production performance however, if any, is unclear.
- Shortly after CO₂ injection began, a program of production enhancement activities unrelated to the CO₂-ECBM pilot was implemented. Those activities included well recavitations, well reconfigurations (conversion from tubing/packer completions to annular flow with a pump installed for well dewatering), line pressure reductions due to centralized compression, and also the installation of on-site compression. These activities largely coincided with the dramatic increase in production observed beginning in mid-1998.

In addition, a plot of injection rate and pressure history for injector well # 143 is shown in Figure 4. Injection was performed at a constant surface pressure, and rate was allowed to vary. Note the reduction in injection rate during early time, presumably due to coal swelling and permeability reduction. The rebound in injectivity during later times is believed due to overall reservoir pressure reduction and resulting matrix shrinkage that occurred near the injector wells.

RESERVOIR DESCRIPTION

The Allison Unit wells produce from three Upper Cretaceous Fruitland Formation coal seams, named the Yellow, Blue and Purple (from shallowest to deepest) using Burlington Resources' terminology. A summary of basic coal depth, distribution, thickness, pressure, and temperature information is provided in Table 1.

Sorption isotherms for both CH₄ and CO₂ were measured for six coal samples taken from three wells within the study area. Average CH₄ and CO₂ isotherms based on these data for each coal interval, on a raw basis and at an average density of 1.5 grams per cubic centimeter (g/cc), are shown in Figures 5 and 6.

In May, 2000, pressure buildup tests were performed on 12 wells in the Allison Unit, eight of which were inside the study area. Analysis of these data provided estimates of effective gas permeability, skin factor, and reservoir pressure. Two adjustments of the results were made to 1) derive absolute permeability from the effective gas permeability results and 2) correct to initial conditions – accounting for both pressure-dependent permeability and matrix shrinkage. The resulting permeability map of the field is shown in Figure 7. Permeability values ranged from 30-150 millidarcies (md), with higher permeabilities

concentrated within the central 5-spot pattern. No permeability anisotropy appeared to exist for the study area.

A novel technique was also used to estimate relative permeability and porosity for the study area based on historical gas and water production. This technique, described in a detailed report on the Allison Unit², provided average relative permeability curves for the study area, as well as a porosity map.

RESERVOIR MODEL CONSTRUCTION

The reservoir simulator used for the study was ARI's COMET2 (binary isotherm – CH₄ and CO₂) model. Details on the model theory are provided in the references^{3,4}.

A three-layer (Yellow, Blue, Purple), full-field model was constructed. The coal structure and thickness information for each layer was directly input per the maps generated. Coal permeability and porosity maps were similarly employed. Relative permeability curves from the analysis mentioned previously, as well as the laboratory isotherms, were also used.

Additionally, well completion and operating parameters were examined for input into the model, such as recavitations, well reconfigurations and producing pressure adjustments. This was particularly important given the complexity of the field history, and the desire to isolate and study the effects of CO₂ injection.

The model gridblock dimensions were 33 x 32 x 3 (approximately 3,200 total grid blocks, 2,600 of which were active), and covered an active area of about 7,100 acres (Figure 8). On average, the gridblock dimensions were 560 feet x 525 feet x 14 feet. The corners of the model were isolated using no-flow barriers to account for producing wells immediately adjacent to these portions of the study area.

HISTORY MATCH RESULTS

The independent parameter used for the simulator was gas production (and injection) rate to maintain material balance, and the dependent (history match) parameters were water production rate, flowing pressure (producing and injecting), and gas composition. Note that only some of these data were available for some periods for some wells; whatever was available was used. In addition, the pressure history at POW #2 was available.

All parameters were modified globally to obtain the best overall match for the field. The objective of the study was to understand the mechanisms of the CO₂-ECBM process by matching general trends, and not necessarily to make regional changes to the reservoir characterization to achieve matches on an individual well basis. While a large number of simulation trials were performed varying almost all significant reservoir parameters, it was ultimately found that the original reservoir characterization seemed to provide the best overall result.

A comparison of the actual versus simulated field gas rate is presented in Figure 9. The only conclusion that can be derived from this result, since the model was "driven" on gas rate, is that model (as constructed) was capable of delivering the gas volumes required.

The actual versus simulated pressure at POW#2 is presented in Figure 10. Actual pressure data is only available after the commencement of CO₂ injection. At that particular point in time (April, 1995), there appears to be excellent agreement between actual and predicted pressure, suggesting that material balance (at least during primary production) was achieved, and hence values for original gas/water storage capacities, as well as depletion characteristics, were reasonable. After that, however, there is considerable difference in pressure values. Of note is that the estimated pressure at the location of POW #2 based on the May, 2000 pressure transient analysis (PTA) is reasonably close to the simulated value. After considerable analysis of the discrepancy it is believed that the pressure data recorded at POW#2

may have been influenced by severe restrictions in wellbore-reservoir connectivity, and therefore may not have been valid.

Comparison plots of gas and water rates, flowing pressures, and produced gas compositions, for well 113 are presented in Figure 11. This well was selected because it was the central well of the 5-spot, it had data for comparison in all categories, and it had observable CO₂ breakthrough. In addition, this well typifies the differences in simulated versus actual results for the other wells. Several general comments can be made regarding the results:

- The quality of the water rate predictions varied, with some being too high and some too low. However, on balance the predictions were considered within reason (and that could be easily “fixed” with regional variations in porosity and/or water relative permeability).
- In all cases, the predicted bottomhole flowing pressures were higher than the measured values – which were actually surface casing pressure data – usually by 200-300 psi. While some difference might be expected due to the different types of data being compared (surface vs. downhole), the magnitude of the difference seems large. (The wells were believed to be pumped-off with little water head existing above the coal seam.) In most cases the predicted flowing pressures appear smooth through the period when the recavitation operations were performed. This result was per the model design.
- In general, the trend in gas composition was reasonably well replicated. In some cases (most noteworthy well #113), the increase in CO₂ content of the produced gas occurs more rapidly than that actually observed.

A comparison of actual to simulated bottomhole injection pressures for CO₂ injector well #142 is provided in Figure 12. Note that the results for the other three injector wells were very similar. The actual bottomhole pressure history data was computed using long-term surface pressure data, and flowing pressure gradients obtained during the August, 2001 injection/falloff tests. The simulated pressures are considerably lower than the actual values. While simulated bottomhole pressures could be increased substantially to better match the actual data by assuming lower initial permeability values for the injector well gridblocks, the objective was to see if the coal swelling formulation in the simulator could adequately account for sufficient permeability reduction to achieve the high injection pressures observed. The result suggests that the answer is negative. Therefore, coal swelling models with CO₂ injection may require further development to adequately replicate field data.

Pressure transient tests performed in August, 2001 in the CO₂ injection wells indicated near-well permeabilities of <1 md, considerably less than the estimated initial values. However, at most injectivity was only cut in half. The apparent discrepancy between the high permeability reduction and comparatively modest injectivity loss was investigated by examining the permeability profile that extended radially from one of the injector wells (#142) at about the time when injectivity was at its lowest value. The result is shown in Figure 13. This plot suggests that the permeability reduction effect is decreased radially from the well, and reached a distance of about 1000 feet. Simple analytic modeling confirmed that this type of permeability reduction profile would yield a reduction in injectivity by about a factor of two, all else being equal.

PERFORMANCE FORECASTS

In order to evaluate the long-term performance of the ECBM pilot, performance prediction cases were simulated using the history match result as the starting point. The specific cases evaluated were:

1. No CO₂ injection (i.e., primary production only).
2. Current conditions (i.e., CO₂ injection until August 2001).
3. Aggressive injection (i.e., CO₂ injection at four times actual rate until August, 2001)

For each ECBM forecast case, an economic limit of 50 Mcfd of methane per well and 50% CO₂ content per well was imposed; reaching those thresholds prompted the well in question to be shut-in in the model. Results of the forecast for the actual pilot conditions indicated that of the 6.4 Bcf of CO₂ injected in the pilot area, 1.6 would ultimately be reproduced. The incremental methane recovery was 1.6 Bcf, yielding a net CO₂/CH₄ ratio of 3.0. Figure 14 presents the simulated sweep of the CO₂ at the end of the forecast period for the pilot. Note that excellent sweep appears to have been achieved in the northern, western, and southern quadrants of the five-spot. However, due to the location of injection well #140, poor sweep was achieved in the eastern quadrant.

Since the model area was so large compared to the actual flooded area, the incremental recovery results were examined for each quadrant of the central 5-spot pattern. Methane recoveries with and without CO₂ injection were computed for each quadrant and are presented in Table 3. This analysis indicates that CO₂-ECBM was highly effective at recovering incremental methane, providing on the order of 17 – 18% of original-gas-in-place where the patterns were configured for effective sweep.

Two additional interesting observations were made regarding the modeling results:

- The stabilized CO₂/CH₄ ratio of about 3:1 is higher than normally cited for San Juan basin coals. However, if one examines the ratio as a function of pressure (based on the isotherms) the results are as expected (Figure 15). At an abandonment pressure of ~50 psi, the CO₂/CH₄ ratio is close to 3:1.
- It appears that some time was required after CO₂ injection ceased for the CO₂ to migrate through the reservoir and displace the “equilibrium” volume of methane. Figure 16 illustrates the CO₂/CH₄ ratio over time for the pilot. Note that the ratio increases during injection periods (and for some time afterwards), and then begins a gradual decline to the equilibrium value.

ECONOMIC ASSESSMENT

The final element of the study was to evaluate the economic performance of the pilot. The capital, operating and financial assumptions are presented in Table 3. Note that all economics were performed on an incremental basis (i.e., only the incremental production and costs were considered). Further, the effect of Section 29 tax credits was not considered.

The analysis first evaluated the performance of the existing pilot, with no future CO₂ injection considered. Note that the hot-tap and pipeline capital costs are included for this case, but only allocated at 25% of the total since the working assumption was that it would also be used for additional pilots and/or large-scale CO₂ flood implementation. The results are presented in Figure 17. There are several points worth making. First, at the prevailing gas price at the time of the pilot (~ \$2.20/Mcf), the project had a negative net present value (NPV), not accounting for Section 29 tax credits. At \$4.00/Mcf however, it would have yielded a peak NPV of \$2 – 3 million. The breakeven gas price for the pilot was \$2.57/Mcf.

Secondly, a peak in NPV occurs approximately five-years after CO₂ injection began. Examination of the incremental methane recovery profile provides insight into this finding, shown in Figure 18. The CO₂ injection resulted in some acceleration of methane recovery, and when the incremental methane rate became negative at later times, the NPV began to drop. This point in time also corresponds to the peak CO₂/CH₄ ratio in Figure 16. The implication is that there may be a fixed, optimum CO₂ volume that should be injected to a given pattern, probably corresponding to the volume of methane in place and the equilibrium CO₂/CH₄ ratio, and any further injection in addition to that volume merely represents additional cost without additional methane recovery. At the Allison Unit pilot, that optimum CO₂ injection volume appears to have been exceeded.

Finally, since the CO₂ injection rate was constrained by pressure limitations and coal swelling. The impact of a higher injection rate was examined. These cases, at \$2.20/Mcf and \$4.00/Mcf, are also

shown on Figure 17. It is clear that higher injection rates substantially improves CO₂-ECBM economic performance. Therefore strategies for mitigating coal swelling and injectivity reduction should be a priority consideration for CO₂-ECBM projects.

CONCLUSIONS

Based on the results of this study, the following conclusions have been drawn:

- The injection of CO₂ at the Allison Unit has resulted in incremental methane recovery over estimated ultimate primary recovery, in approximately a proportion of one volume of methane for every three volumes of CO₂ injected. Methane recoveries of 17 - 18% of original-gas-in-place were estimated for effectively swept portions of the 5-spot.
- At the prevailing gas prices at the time the project was implemented (~\$2.20/Mcf), and not considering any tax credit benefits, the pilot itself was uneconomic. However, with today's gas prices of ~\$4.00/Mcf, CO₂-ECBM appears economically attractive. The breakeven gas price for the conditions at Allison was estimated to be ~ \$2.60/Mcf.
- There appears to be clear evidence of significant coal permeability reduction with CO₂ injection. This permeability reduction, and the associated impact on CO₂ injectivity, compromised incremental methane recoveries and project economics. Finding ways to overcome and/or prevent this effect is therefore an important topic for future research.

ACKNOWLEDGEMENTS

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- 2) Reeves, S.R., Taillefert, A. Pekot, L., and Clarkson, C.: "The Allison Unit CO₂ – ECBM Pilot: A Reservoir Modeling Study", Topical Report, DOE Contract No. DE-FC26-00NT40924, February, 2003.
- 3) Reeves, S. and Pekot, L.: "Advanced Reservoir Modeling in Desorption-Controlled Reservoirs," SPE 71090, presented at the SPE Rocky Mountain Petroleum Technology Conference, Keystone, May 21-23, 2001.
- 4) Sawyer, W.K., Paul, G.W., Schraufnagel, R.A., "Development and Application of a 3D Coalbed Simulator," CIM/SPE 90-119, presented at the CIM/SPE International Technical Conference, Calgary, June 10-13, 1990.

Table 1: Basic Coal Reservoir Data, Allison Unit

Property	Value
Average Depth to Top Coal	3,100 feet
Number of Coal Intervals	3 (Yellow, Blue, Purple)
Average Total Net Thickness	43 feet <div style="text-align: right; padding-right: 20px;">Yellow - 22 ft</div> <div style="text-align: right; padding-right: 20px;">Blue - 10 ft</div> <div style="text-align: right; padding-right: 20px;">Purple - 11 ft</div>
Initial Pressure	1,650 psi
Temperature	120° F

Table 2: Incremental Recovery by Quadrant, Case 2 vs. Case 1

Quadrant	Recovery (% OGIP)		
	w/o CO ₂	w/ CO ₂	Incremental
North	77%	94%	17%
West	77%	95%	18%
South	77%	95%	18%

Table 3: Economic Analysis Assumptions

Capex CO ₂ Hot Tap: 36 mi (4 inch) Pipeline: Field Distribution: Wells	<table style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 50%;">\$175,000</td> <td style="width: 5%;"></td> <td style="width: 45%;"></td> </tr> <tr> <td>\$3.5 million (\$24,000/in-mi)</td> <td style="font-size: 2em;">}</td> <td>Allocated</td> </tr> <tr> <td>\$80,000 (\$20,000/in-mi)</td> <td></td> <td>@ 25%</td> </tr> <tr> <td>\$1.6 million (\$400,000/ea; fully equipped)</td> <td></td> <td></td> </tr> <tr> <td style="text-align: right; border-top: 1px solid black;">Total</td> <td></td> <td style="border-top: 1px solid black;">\$5.355 million</td> </tr> </table>	\$175,000			\$3.5 million (\$24,000/in-mi)	}	Allocated	\$80,000 (\$20,000/in-mi)		@ 25%	\$1.6 million (\$400,000/ea; fully equipped)			Total		\$5.355 million
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Total		\$5.355 million														
Opex Injector Well Operating: CO ₂ Cost Produced Gas Processing	<table style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 50%;">\$1,000/mo (active only)</td> <td style="width: 50%;"></td> </tr> <tr> <td>\$0.30/Mcf</td> <td></td> </tr> <tr> <td>\$0.25/Mcf</td> <td></td> </tr> </table>	\$1,000/mo (active only)		\$0.30/Mcf		\$0.25/Mcf										
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Financial Gas Price: Methane BTU Content Net Revenue Interest: Production Taxes: Discount Rate:	<table style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 50%;">\$2.20/MMBTU (ex-field)</td> <td style="width: 50%;"></td> </tr> <tr> <td>1.04 MMBTU/Mcf</td> <td></td> </tr> <tr> <td>87.5%</td> <td></td> </tr> <tr> <td>8%</td> <td></td> </tr> <tr> <td>12%</td> <td></td> </tr> </table>	\$2.20/MMBTU (ex-field)		1.04 MMBTU/Mcf		87.5%		8%		12%						
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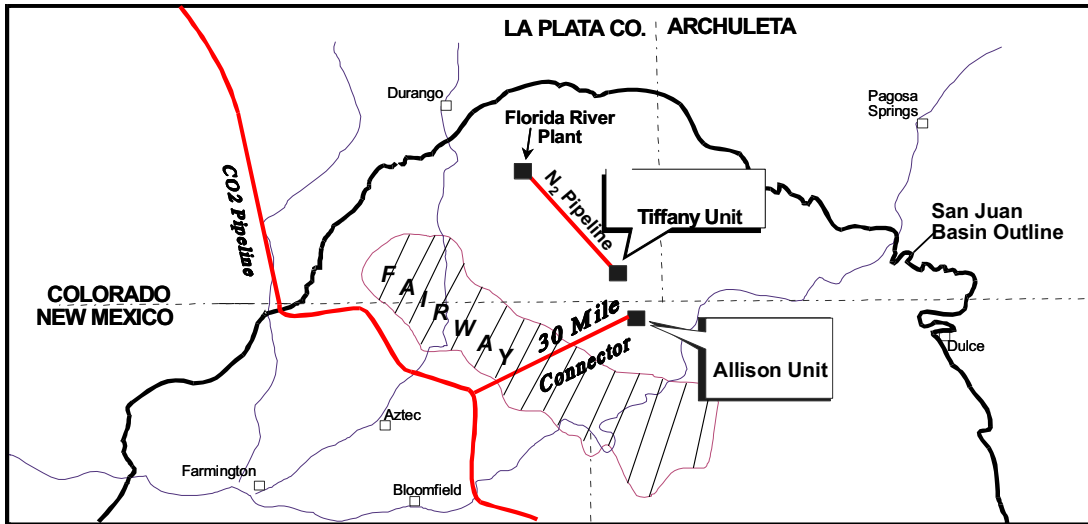


Figure 1: Location of the Allison Unit, San Juan Basin

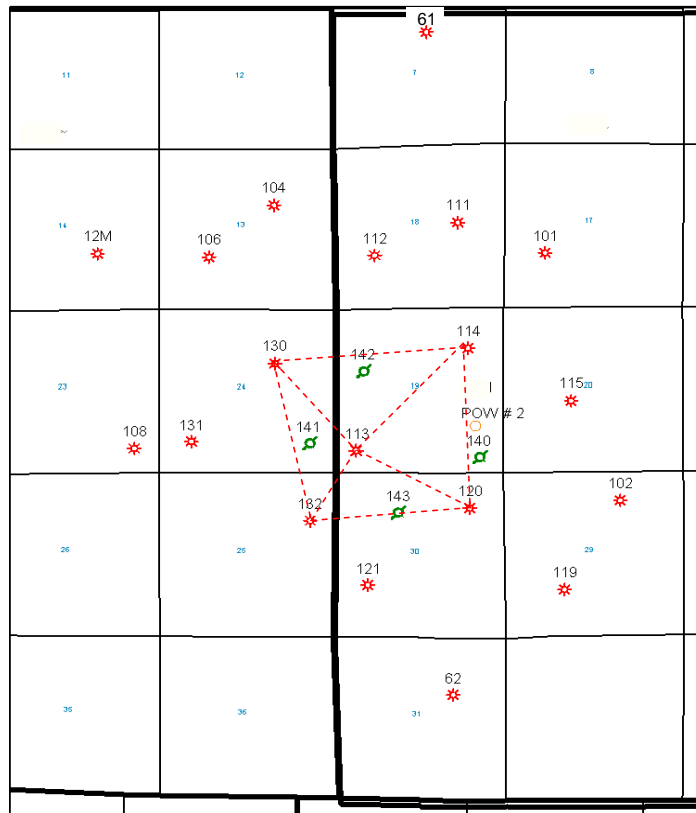


Figure 2: Producer/Injector Well Pattern, Allison Unit Study Area

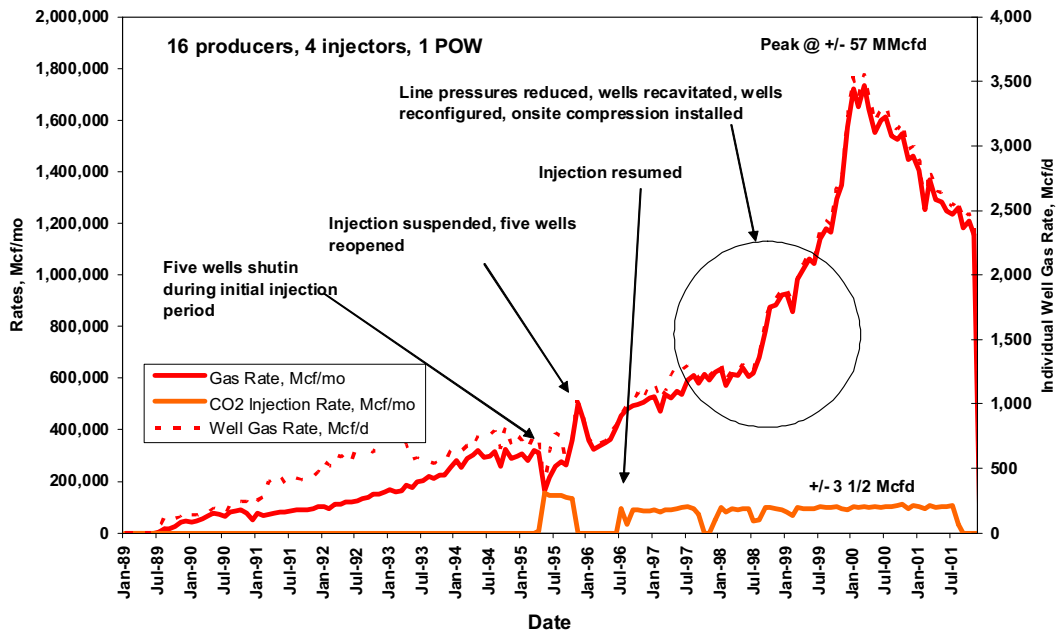


Figure 3: Producing History, Allison Unit Study Area

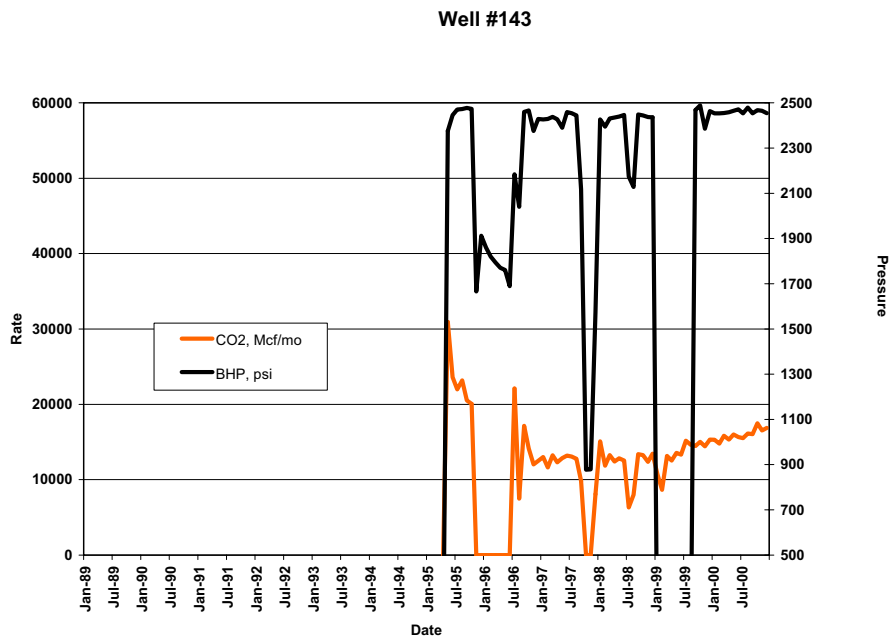


Figure 4: Injector Well # 143 Injection and Pressure History

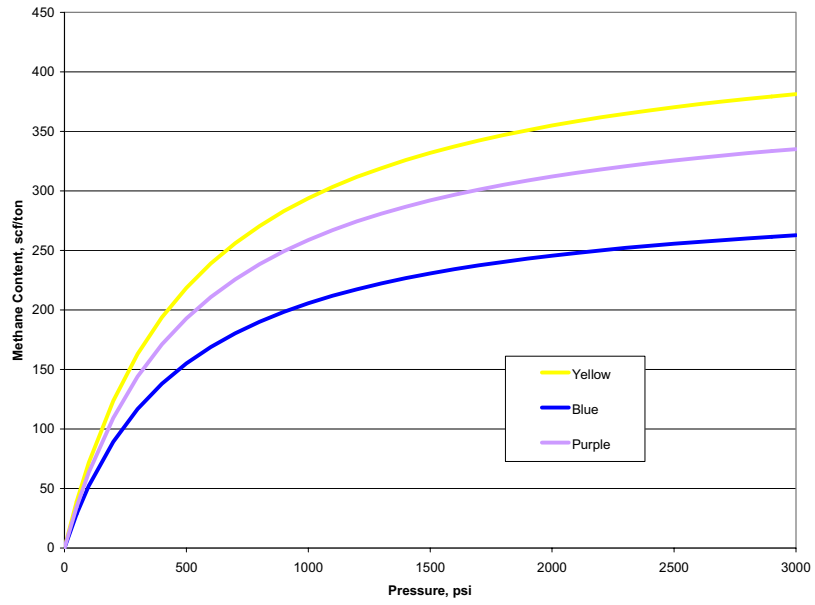


Figure 5: Methane Sorption Isotherms, Allison Unit Study Area

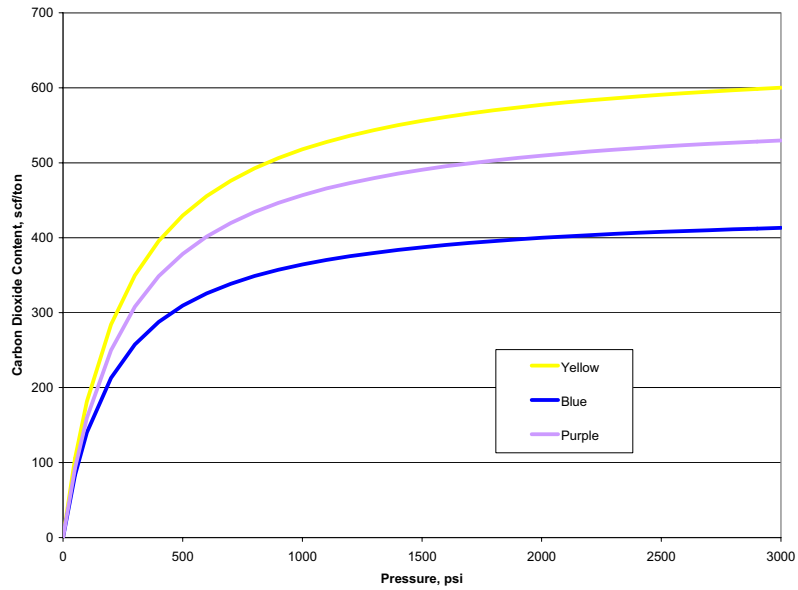


Figure 6: Carbon Dioxide Sorption Isotherms, Allison Unit Study Area

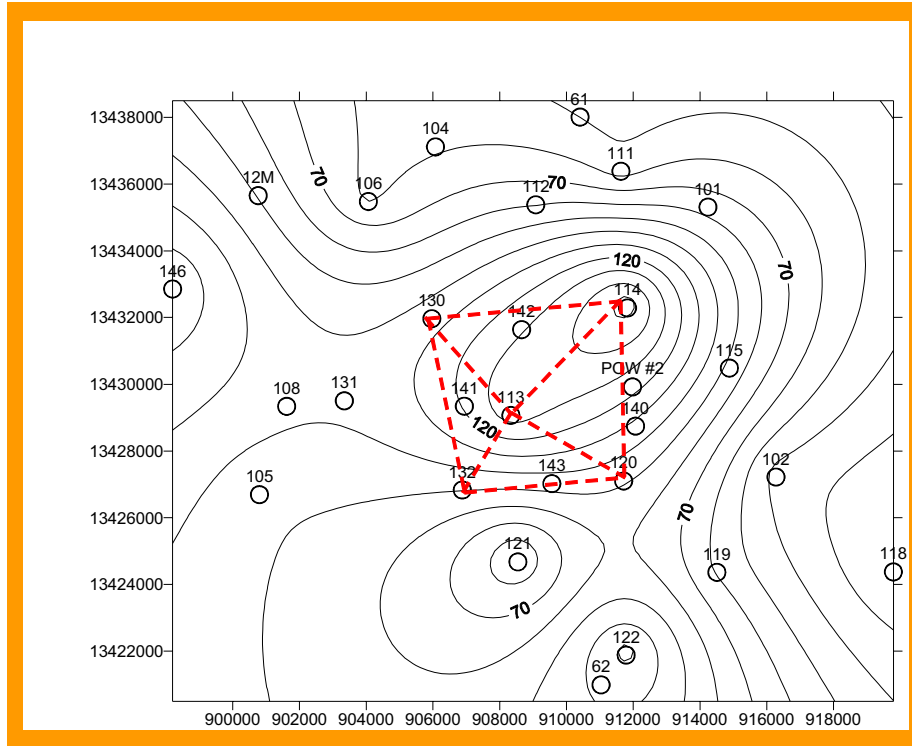


Figure 7: Permeability Map for Allison Unit Study Area

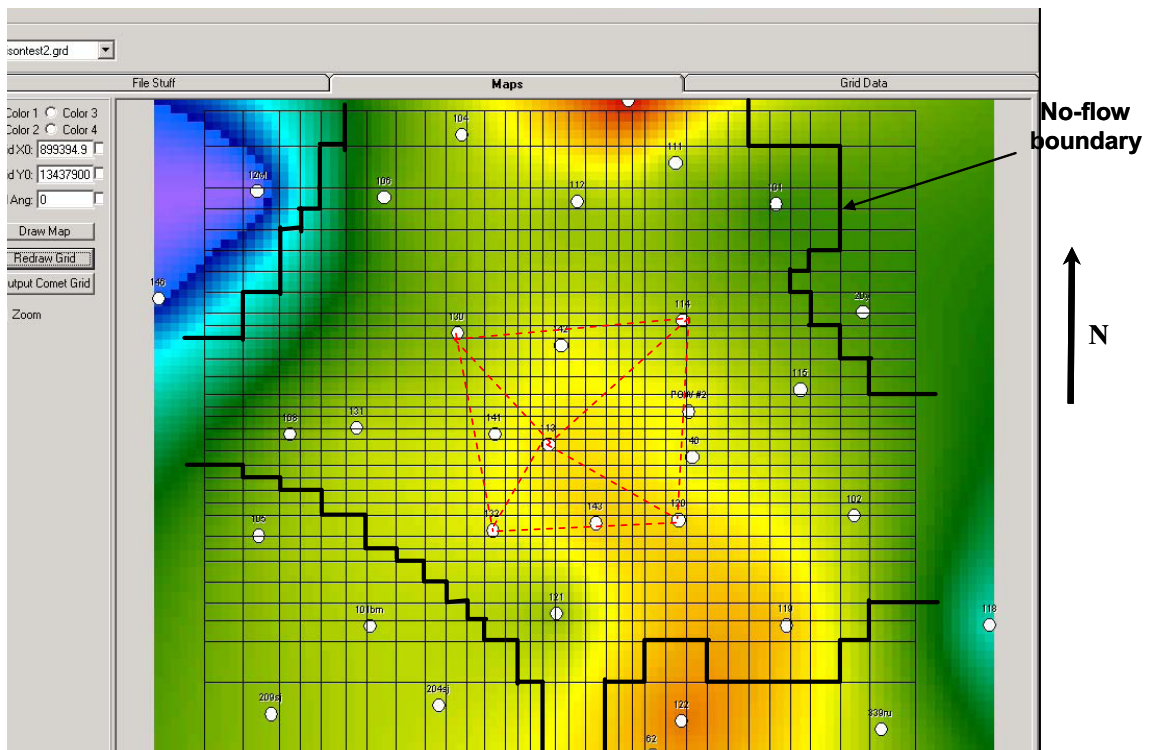


Figure 8: Map View of the Middle Layer of the Simulation Model

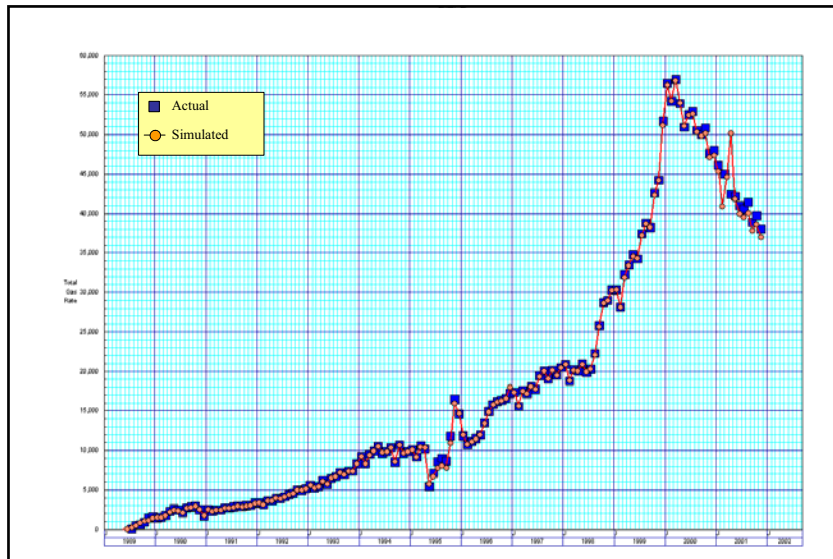


Figure 9: Actual versus Simulated Field Gas Rate, Allison

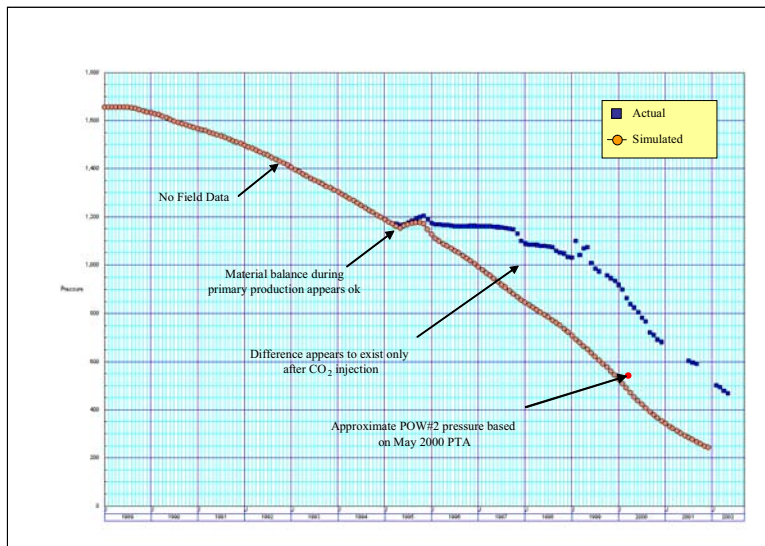


Figure 10: Actual versus Simulated Pressure at POW#2

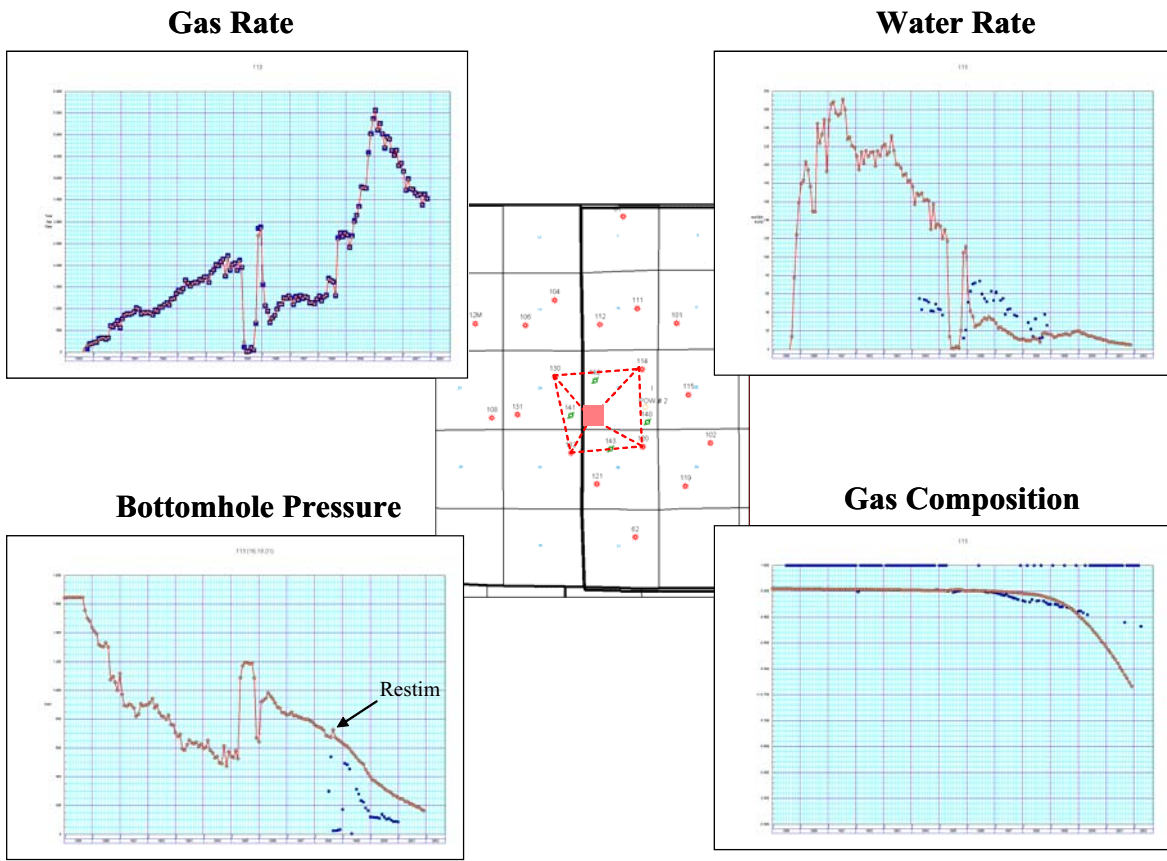


Figure 11: Comparison of Predicted to Actual Well Performance, Well 113

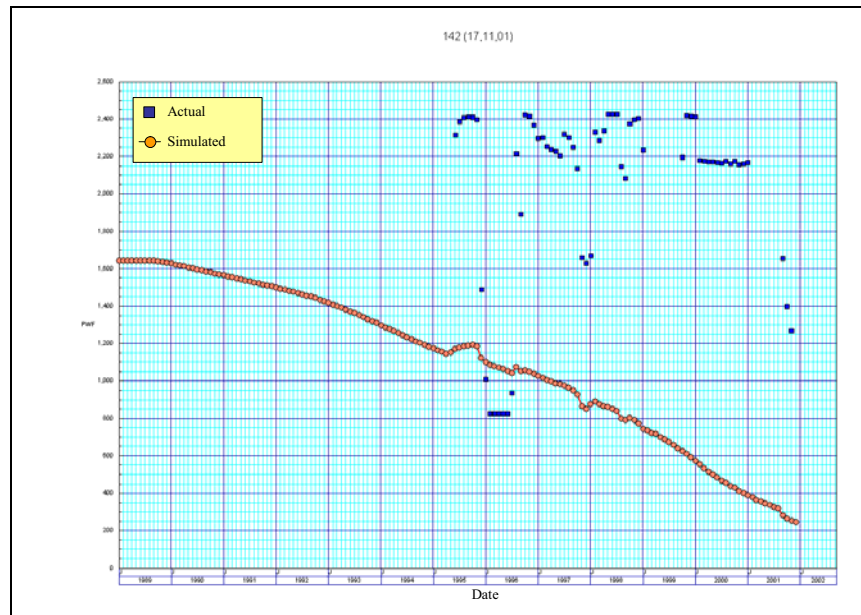


Figure 12: Comparison of Predicted to Actual Bottomhole Injection Pressures, Injection Well #142

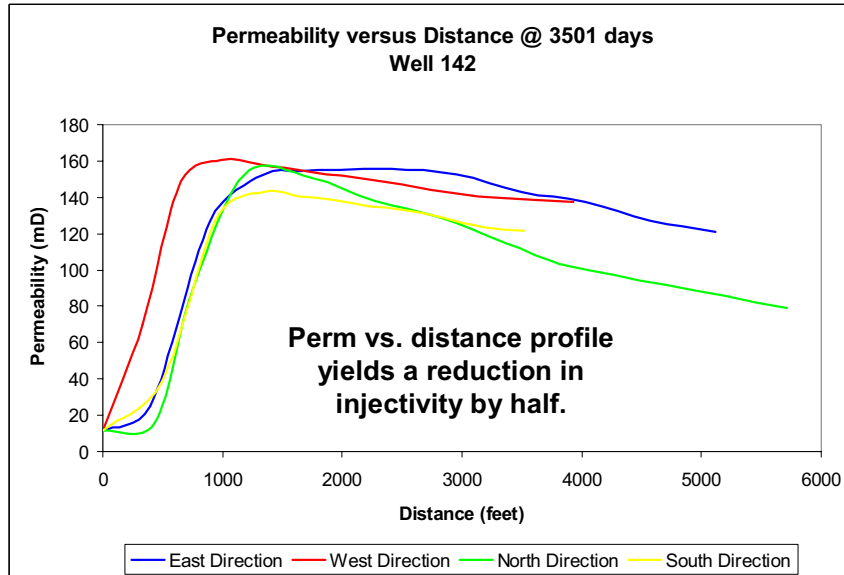


Figure 13: Simulated Permeability Profile from Injector Well #142

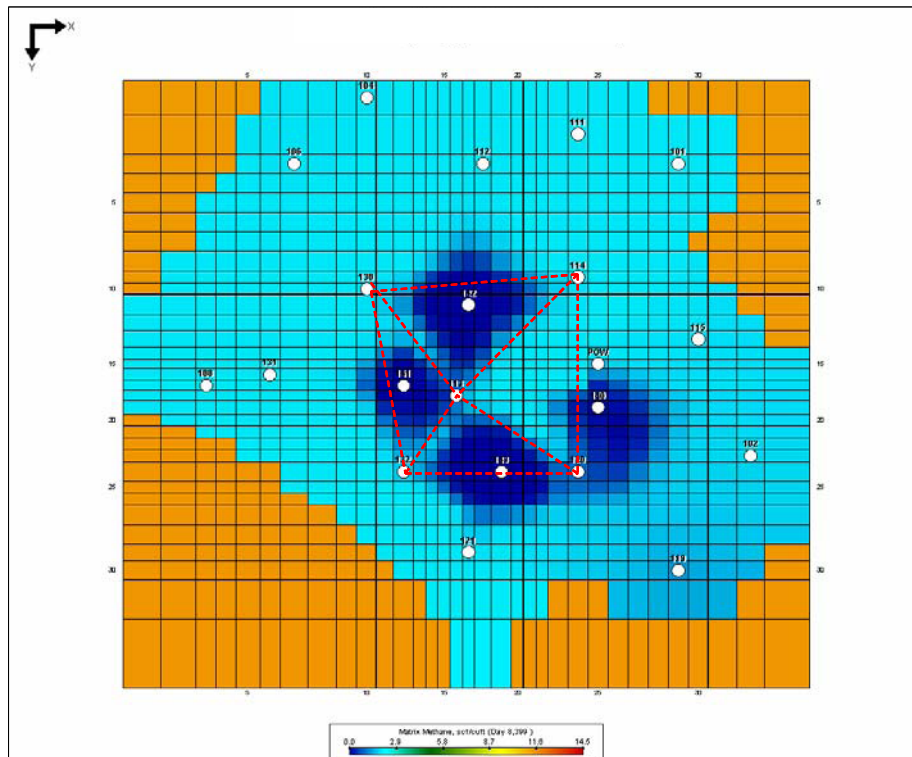


Figure 14: Map View of Methane Content (Layer 2) at End of Forecast Period (Case 2)

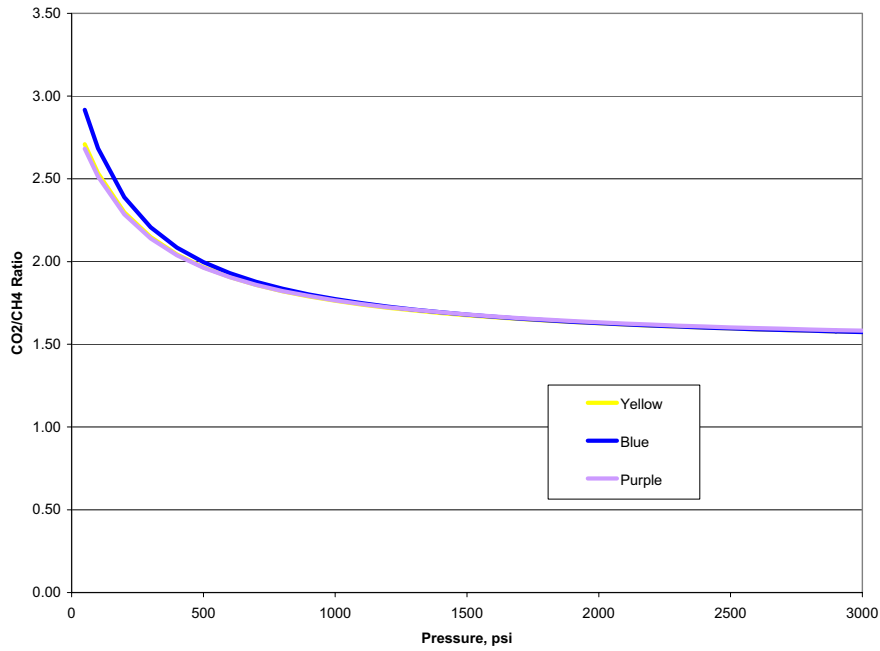


Figure 15: CO₂/CH₄ Ratio vs. Pressure

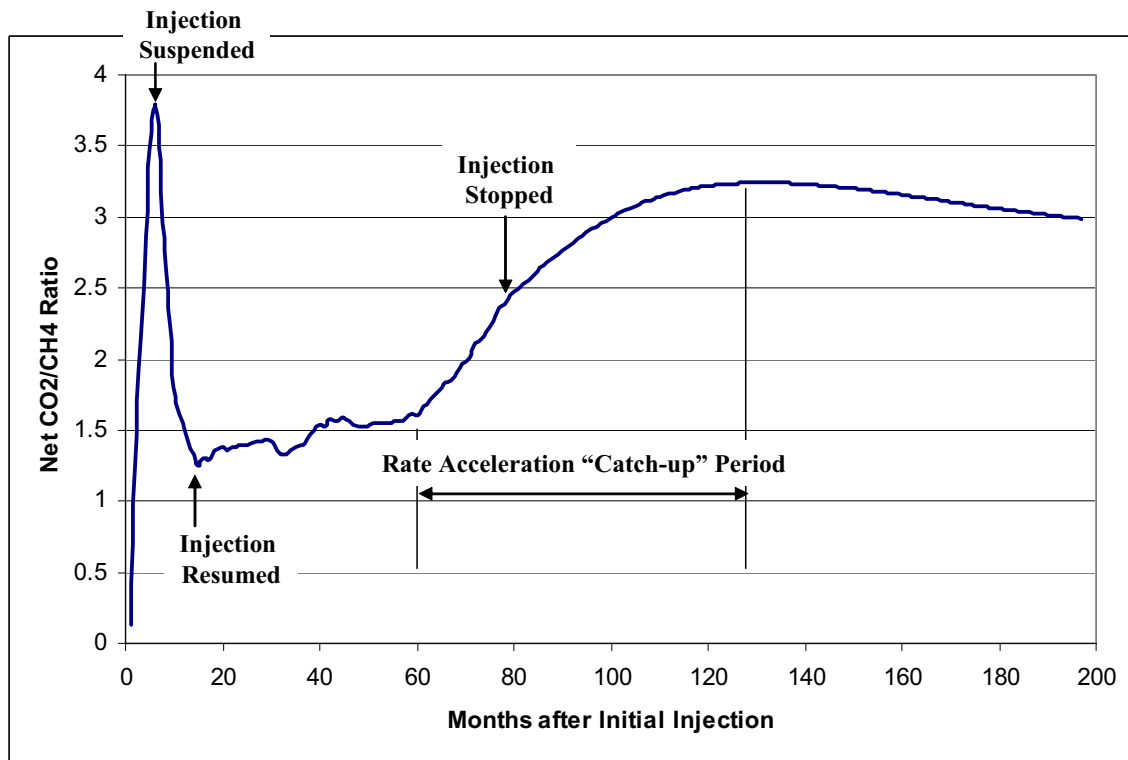


Figure 16: CO₂/CH₄ Ratio vs. Time, Allison Unit Pilot

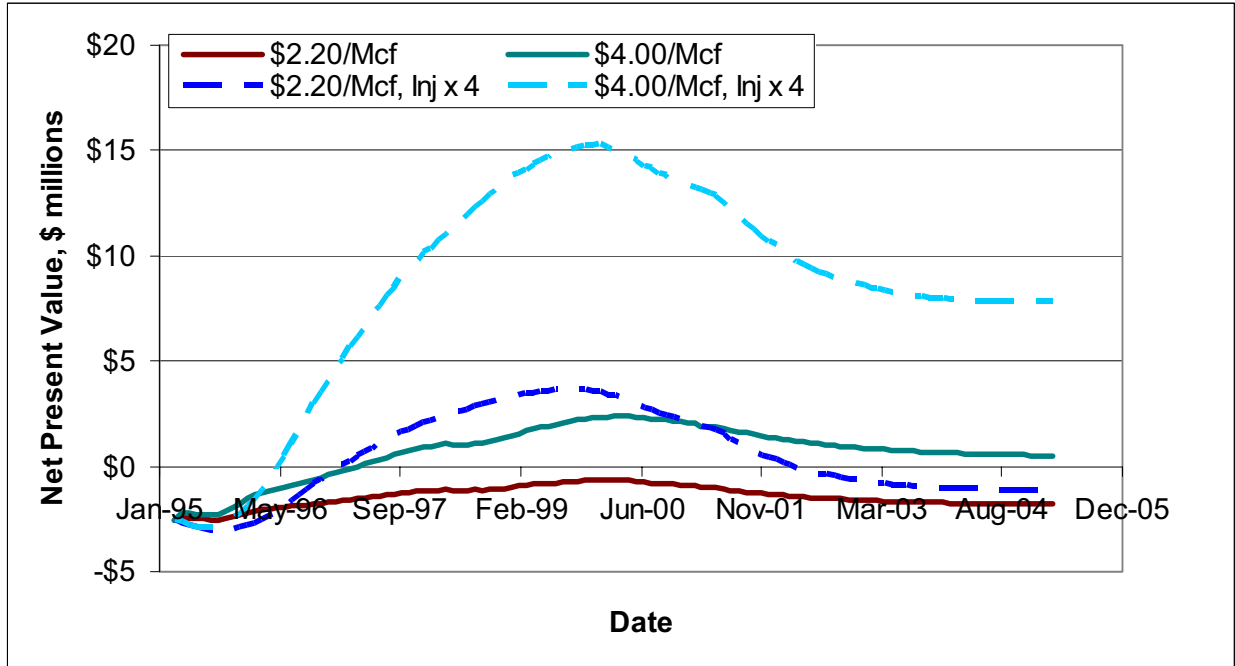


Figure 17: Economic Analysis Results, Case 2 vs. Case 1

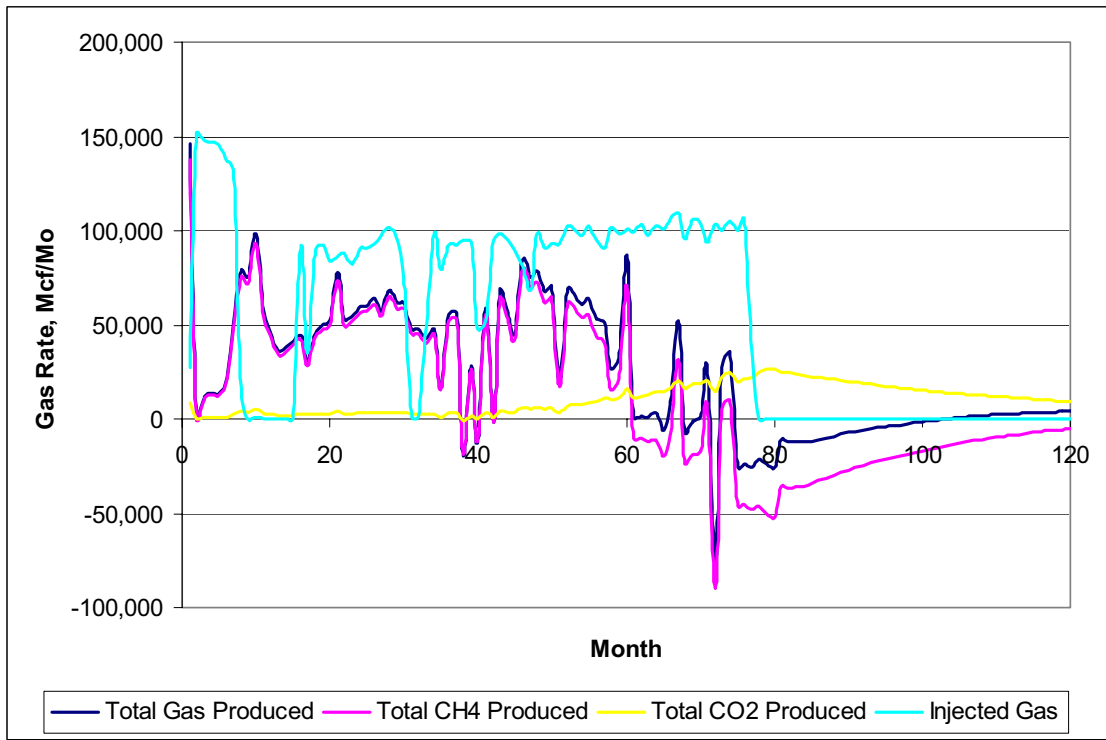


Figure 18: Incremental Gas Rates, Case 2 vs. Case 1