Title: **"Improved Miscible Nitrogen Flood Performance Utilizing Advanced Reservoir Characterization and Horizontal Laterals in a Class I Reservoir – East Binger (Marchand) Unit"**

Type of Report: **Quarterly Technical Progress (Report No. 15121R12)**

Reporting Period Start: **January 1, 2003**

Reporting Period End: **March 31, 2003**

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Report Date: **May 30, 2003**

Cooperative Agreement No: **DE-FC26-00BC15121**

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Disclaimer

Abstract

Implementation of the work program of Budget Period 2 of the East Binger Unit ("EBU") DOE Project continues. Significant advances with the reservoir simulation model have led to changes in the program. One planned horizontal well location, EBU 44-3H, has been eliminated from the program, and another, EBU 45-3H, has been deferred, and may be replaced by a vertical well or completely eliminated at a future date. A new horizontal well location, EBU 63-2H, has been added.

EBU 74G-2, the one new injection well planned for the project, was completed and brought on production. It will be produced for a period of time before converting it to injection. Performance is exceeding expectations.

Work also continued on projects aimed at increasing injection in the pilot area. EBU 65-1 was converted to injection service. The project to add compression and increase injection capacity at the nitrogen management facility is nearing completion. Additional producer-to-injector conversions will follow.

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Quarterly Technical Progress Report – 1st Quarter 2003

Introduction

Implementation of the work program of Budget Period 2 of the East Binger Unit ("EBU") DOE Project is progressing. Changes have been made to the development plan based on results of simulation model forecasts. Major development work initially planned for the project included the drilling of three horizontal production wells and one vertical injection well, the conversion of five wells from production to injection service, and the expansion of injection capacity at the nitrogen management facility.

This quarterly report covers the First Quarter of 2003. Well EBU 74G-2, the vertical injection well, was completed and put on production in this quarter. It will be produced for a period of time prior to conversion. Well EBU 65-1 was converted at the beginning of this reporting period. Expansion of the injection capacity at the plant has been delayed slightly but is nearing startup.

Initial forecasting cases with the revised simulation model have been completed. Results suggest that well locations not previously evaluated are more attractive and economic than locations previously planned for development. These results are presented in this report.

Additional data gathering was completed and will also be discussed.

Executive Summary

Implementation of the work program of Budget Period 2 of the East Binger Unit ("EBU") DOE Project continues. Significant advances with the reservoir simulation model have led to changes in the program. One planned horizontal well location, EBU 44-3H, has been eliminated from the program, and another, EBU 45-3H, has been deferred, and may be replaced by a vertical well or completely eliminated at a future date. A new horizontal well location, EBU 63-2H, has been added.

EBU 74G-2, the one new injection well planned for the project, was completed and brought on production. It will be produced for a period of time before converting it to injection. Performance is exceeding expectations.

Work also continued on projects aimed at increasing injection in the pilot area. EBU 65-1 was converted to injection service. The project to add compression and increase injection capacity at the nitrogen management facility is nearing completion. Additional producer-to-injector conversions will follow.

Experimental

The goal of this project is to improve the performance of the miscible nitrogen flood of the East Binger Unit through the use of reservoir characterization and horizontal laterals. The reservoir characterization was, and is continuing to be, conducted through standard methods of geologic study, performance analysis, and reservoir simulation. Horizontal drilling is now also a fairly common practice in the industry.

The performance of the flood, and the degree to which it is improved by this project, will be evaluated through standard methods of projecting ultimate recovery such as decline curve analysis, estimating percent recovery versus pore volumes injected, and, more immediately, the impact on the cycling of injected gas. This, in turn, will be monitored primarily with compositional analyses of produced gas. All of these performances techniques are discussed in previously published literature.[1-3]

Results and Discussion

The following is a detailed review of the work conducted in this reporting period.

Task 1.2.1 – Drill New Horizontal Producing Wells

Figure 1 shows the pilot area. Plans for wells to be drilled in this task have been revised based on reservoir simulation work conducted under Task 1.2.9. The specific results of the simulation work are discussed in the Task 1.2.9 section later in this report.

Figure 2 shows the locations of the three horizontal producing wells – EBU 44-3H, EBU 45-3H, and EBU 64-3H – originally planned to be drilled as part of this task. EBU 64-3H was drilled and completed in 2002 and is currently on production. Based on the simulation work, EBU 44-3H has been removed from the program, while a new location, EBU 63-2H, has been added. The location of EBU 63-2H is shown in Figure 3. EBU 45-3H or another well may be drilled later, depending on the performances of all new wells.

At the end of this reporting period, EBU 64-3H had been on production for about seven months. As shown in Figure 4, it is producing about 80 bopd at a formation GOR of about 4.0 Mcf/stb. Raw nitrogen gas lift was installed in January after the well started to load up due to a lack of reservoir pressure / formation gas. Injection support in the area should improve following the conversion to injection of EBU 65-1, north of the toe of the lateral, in January.

Task 1.2.2 – Drill New Injection Well(s)

EBU 74G-2, the location of which is shown in Figure 2, was completed as a producing well in late January 2003. The well will be produced for two to six months before converting it to injection service. Like EBU 64-3H, this well also penetrated an unswept area. The nitrogen content of the produced gas is only 10%, below the 17% in EBU 64-3H and well below the field average of over 70%. EBU 74G-2 is currently producing about 85 bopd at a formation GOR of about 1.6 Mcf/stb, far exceeding the expected level of 30 – 40 bopd. Its performance history is shown in Figure 5.

Task 1.2.3 – Convert Producers to Injection

Five conversions are planned for Budget Period 2, as shown in Figure 3. As previously reported, EBU 57-1 and EBU 65-1 have been converted. The conversion of EBU 59-1 has been delayed due to delays with the expansion of gas injection capacity at the plant (Task 1.2.4). This is now expected to occur in early May.

The fourth conversion will be EBU 37-3H. This well was selected over EBU 44-1 based on simulation work conducted under Task 1.2.9. This was planned to also coincide with the start up of the plant injection capacity expansion, but may be deferred while the gas inflow to and discharge from the plant stabilize following other changes.

EBU 61-1 is slated for conversion later in 2003.

Task 1.2.4 – Construct, Modify, and Upgrade Plant Capacities

The installation of the additional injection compression is almost complete. All components have been purchased and installed except for one item requiring additional modifications. Delivery of this item is expected in early May. Installation and startup will occur shortly thereafter. Nitrogen injection capacity will then increase to about 22 MMscf/d from the current 19 MMscf/d.

Task 1.2.5 – Initiate Monitoring of Pilot Area Performance

Gas sampling continues in the pilot area. Data collected is presented in Figure 6. While gas compositions for most of the wells are continuing on the trends established before any horizontal wells were drilled, there are some changes. Wells EBU 36-1 and EBU 37-2 have seen the most significant changes. As shown in Figure 2, both are in the vicinity of EBU 37-3H, which was drilled in Budget Period 1 and brought on line in November 2001. EBU 36-1 is east of the heel of EBU 37-3H, while EBU 37-2 lies to the north.

It has previously been determined that the dominant flow direction in the Marchand C Sand is roughly east-west (see Quarterly Technical Progress Reports 15121R08, 1Q 2002). Changes in the produced gas compositions from wells in the area of EBU 37-3H are consistent with this determination. After EBU 37-3H was brought on production, the nitrogen content in the produced gas at EBU 36-1 dropped significantly – and is still dropping. This is because EBU 37-3H is intercepting gas injected in EBU 38G-1 which was previously moving through the reservoir toward EBU 36-1. Oil production from EBU 36-1 has also increased over 30%, from 22 bopd to 29 bopd.

The impact at EBU 37-2 has been less dramatic in percentage change, but still significant. Since EBU 37-3H does not lie between EBU 38G-1 and EBU 37-2, the impact was more indirect. As shown in Figure 6, the nitrogen content of the gas produced from EBU 37-2 dropped from 83% to 77%, but has since increased back up to 80%. Oil rate has been flat through the period.

Gas sampling as well as pressure and profile monitoring will continue throughout the project.

Task 1.2.6 – Technology Transfer Activities

Additional technical progress reports have been posted on the project web site, www.eastbingerunit.com.

Task 1.2.9 – Modify and Update Simulation Model, etc.

Potential drilling locations and conversion scenarios in the pilot area have been evaluated with the reservoir simulation model. Plans to convert EBU 37-3H (Task 1.2.3) and to drill producing well EBU 63-2H (Task 1.2.1) are based on recent model forecasts. The revised history match of the model was completed in the prior reporting period and discussed in Quarterly Technical Progress Report 15121R11 (4Q 2002).

The first evaluation conducted with the model was a comparison of converting EBU 37-3H to injection versus converting EBU 44-1 to injection. Throughout this project, it has been recognized that the northwestern end of the pilot area, specifically the area around EBU 37-3H, is in need of additional injection support. Of all pressure buildup measurements obtained over the past few years, the lowest measured reservoir pressure is 1900 psi at EBU 43-1. Indeed, EBU 37-3H, drilled for data-gathering purposes as part of Budget Period 1, was initially planned as an injection well with a different orientation. This plan was later modified, with EBU 37-3H completed as a producer and a second Budget Period 1 data-gathering lateral eliminated. Although Binger Operations believed it was still appropriate to convert EBU 37-3H to injection, the decision was made to defer the conversion until the revised pilot model could be used to evaluate the benefits and compare them with an alternative scenario of converting EBU 44-1.

Tabulated results from predictive cases converting EBU 37-3H and (alternatively) EBU 44-1 to injection are presented in Figure 7. Although the conversion of EBU 44-1 is projected to provide a quicker investment payout (2.4 years versus 4.0 years) and a higher cumulative cash flow after five years ($422,000 versus $400,000), the predicted long term benefits clearly favor the conversion of EBU 37-3H. The conversion of EBU 37-3H is projected to result in significantly more oil (280,000 bbls versus 120,000 bbls) and NGL (48,000 bbls versus 6,000 bbls) recovery than is the conversion of EBU 44-1. Converting EBU 37-3H is also projected to cost less than converting EBU 44-1, due to the lesser amount of well work required to prepare it for injection as well as the proximity to existing gas injection lines. As shown in Figure 7, the incremental net present value of the simulation case with the EBU 37-3H conversion far exceeds that of the case with the EBU 44-1 conversion. Based on these results, the decision was made to convert EBU 37-3H, as mentioned in the Task 1.2.3 discussion earlier in this report.

A second set of forecast cases has been run to evaluate the optimum location for the next horizontal well. A variety of scenarios were evaluated – horizontal and vertical wells, with and without injection well sidetracks in certain cases. Locations of the wells evaluated are shown in Figure 8, and results are tabulated in Figure 9.

Initially, four horizontal well locations were evaluated: EBU 45-3H (case 3c), EBU 43-2H (case 4c, with a sidetrack of EBU 62G-1), EBU 59-3H (case 5c, with a sidetrack of EBU 63G-1) and EBU 63-2H (case 6c, also with a sidetrack of EBU 63G-1). EBU 44-3H, shown in Figure 2 and originally planned as a development well in Budget Period 2, was eliminated from consideration based on predicted sweep in the area in which it was planned. This was discussed in the previous report, 15121R11 (4Q 2002).

As shown in the results table (Figure 9), case 6c is the best of these four development cases. It has the highest incremental oil and oil-equivalent (BOE) recovery, nearly the quickest payout, and the highest incremental net present value.

Most surprising among the model results is the relatively low projected recovery for EBU 45-3H, which had been planned as the next well to be drilled. The model projects incremental NGL and methane recovery, but a loss of oil recovery associated with the drilling of this well. The primary cause of this loss in oil recovery is a reduction in oil recovery at EBU 45-2, directly west of the planned location of EBU 45-3H. This is caused by increased gas influx from the injection wells to the north, EBU 45G-1 and EBU 46G-1, associated with the high drawdown of horizontal well EBU 45-3H. This northern gas is less extensive near EBU 46-2, so another case – case 6e – was run with this horizontal well moved slightly to the east. As shown in the table, the results of this case are much better, and on par with the other horizontal cases.

Additional cases (4d and 6d) were run to evaluate the value of the injection well sidetracks. The injection well sidetracks were initially included in many of these cases because EBU 62G-1 and EBU 63G-1 are located in thin pay and inject little to no gas in their present locations. It appears that these sidetracks are not justified without improvements in horizontal well productivity.

Case 4d includes the drilling of EBU 43-2H, like case 4c, but without the sidetrack of injection well EBU 62G-1. As shown in Figure 9, the lack of injection support from the sidetracked well leads to significantly less recovery, but the reduced capital cost improves the overall economics – quicker payout, higher 5-year cash flow, and higher discounted net present value.

Case 6d is a corollary to case 6c. Both include the drilling of EBU 63-2H. Case 6c includes a sidetrack of EBU 63G-1, while case 6d does not. Here the results are somewhat different the case 4d versus case 4c comparison. Without the injection support from EBU 63G-1, there is significantly less oil recovery, but significantly *more* NGL and methane recovery, due to the higher formation gas production. On an equivalent barrel (BOE) basis, the recoveries are similar. With less capital required without the sidetrack, the economics clearly favor case 6d.

Results from the comparative cases involving injection well sidetracks suggest sidetracking these edge wells to support offtake from new horizontal wells is not justified at this time – based on the model-projected productivity of the horizontal wells. This productivity is based on the productivity of horizontal wells drilled to date. If this productivity can be enhanced through improved completion and stimulation methods, this will need to be re-evaluated.

Finally, two cases (3f and 6e) were run to compare vertical infill wells with horizontal infill wells. Results suggest that unless horizontal well productivity can be improved (or sustained at a high level for a longer period of time through increased pressure support), or the cost of horizontal wells reduced, the additional cost and risk of horizontal wells is not justified. The first comparison is case 3f with cases 3c and 3e. Case 3f includes the drilling of EBU 45-3 as a vertical infill well, located approximately half way between the mid-points of the laterals of cases 3c (EBU 45-3H) and 3e (EBU 46-3H). Projected incremental recovery is approximately the average of the projected incremental recoveries of the two horizontal cases. Capital cost is less than half that of the horizontal well cases, resulting in an improved discounted net present value. The payout is similar because the vertical well does not have the high initial rate.

The second vertical versus horizontal comparison is case 6e versus case 6c. Here the vertical well case outperforms the horizontal well case by all measures – higher projected recovery, lower initial investment, quicker payout, and of course higher net present values. Still, one must recognize that these projections are based on horizontal well productivities of the first two horizontal wells. With only two horizontal wells drilled to date, more data is required before one can conclude that they are not justified in this field. Additional steps will be taken on the next horizontal well in an effort to enhance productivity.

Conclusion

Planning and implementation of the pilot project of the East Binger Unit DOE Project continues. Two of the four wells initially planned, EBU 64-3H and EBU 74G-2, have been drilled and completed. Based on new simulation modeling, the location of third planned well has been changed to a more optimal location, and the fourth well has been eliminated. A new fourth well will likely be added back to the plan after the third well is drilled and brought on production and additional evaluation work is completed.

Work also began on projects aimed at increasing injection in the pilot area. Two of the five planned producer-to-injector conversions have been done, with the third and fourth conversions expected in the next calendar quarter. The expansion of injection capacity at the nitrogen management facility experienced a slight delay but should be completed in May 2003.

Initial forecasting with the revised simulation model has also been completed. Decisions on producer-to-injector conversions and development drilling locations have been finalized based on results of these forecasts.

References

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3. Masoner, L.O., Abidi, H.R., and Hild, G.P.: “Diagnosing CO2 Flood Performance Using Actual Performance Data”, SPE 35363 presented at the 1996 SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 21-24, 1996.

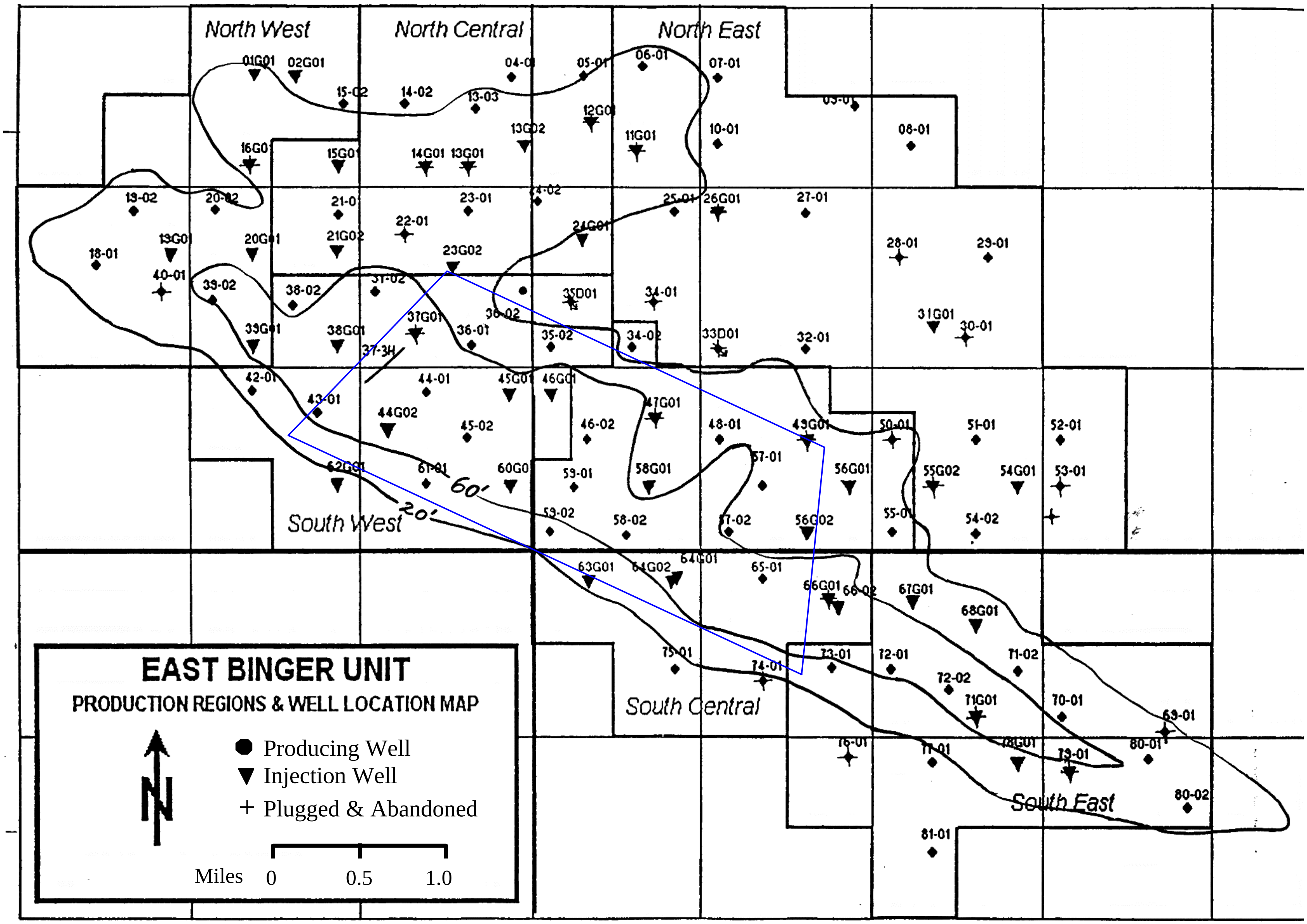

Figure 1. East Binger Unit net pay map. The blue box surrounds the pilot area.

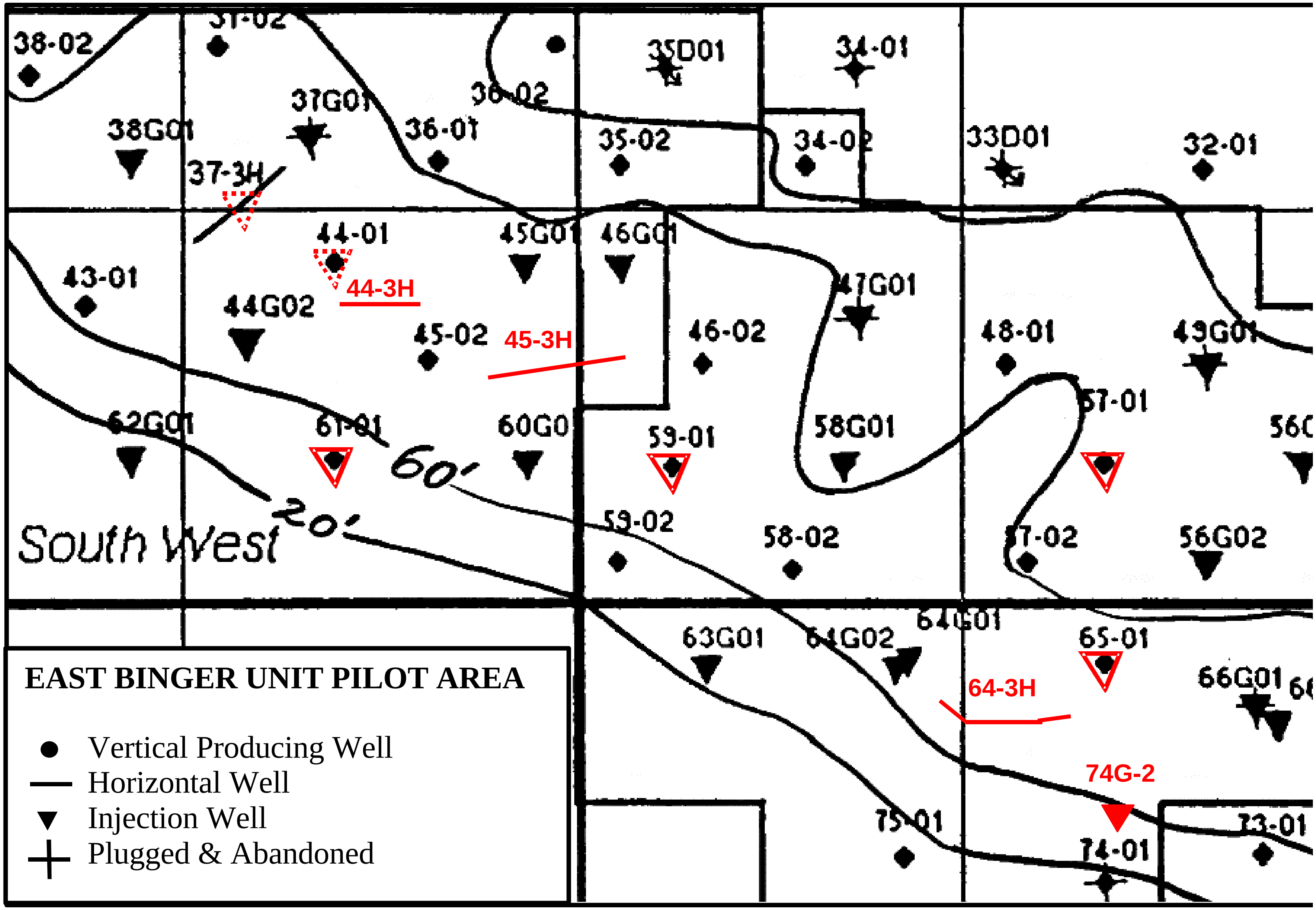

Figure 2. Fieldwork originally planned for the pilot - shown in red. Either 37-3H or 44-1 was planned for conversion to injection.

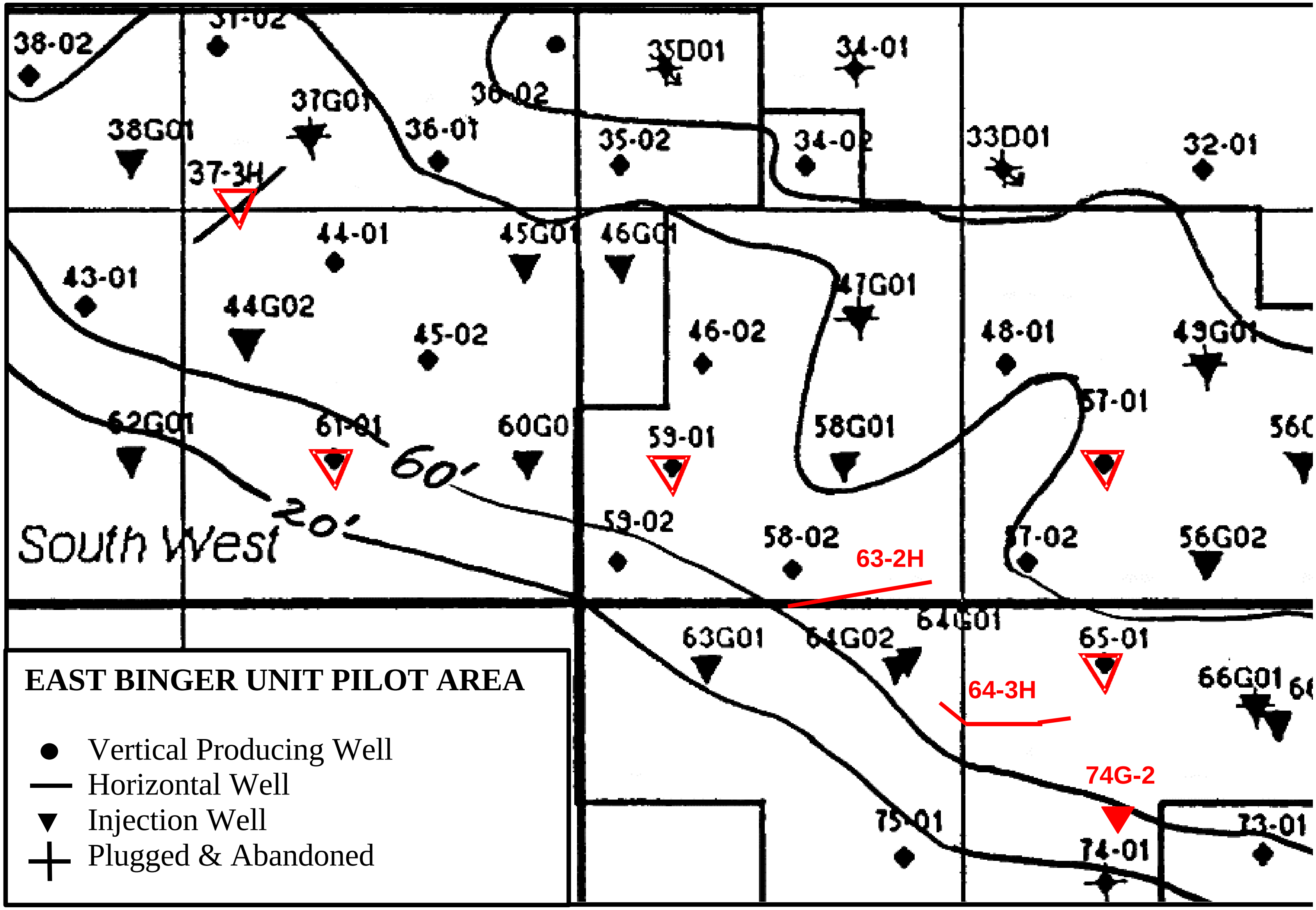

Figure 3. Fieldwork currently planned for the pilot - shown in red.

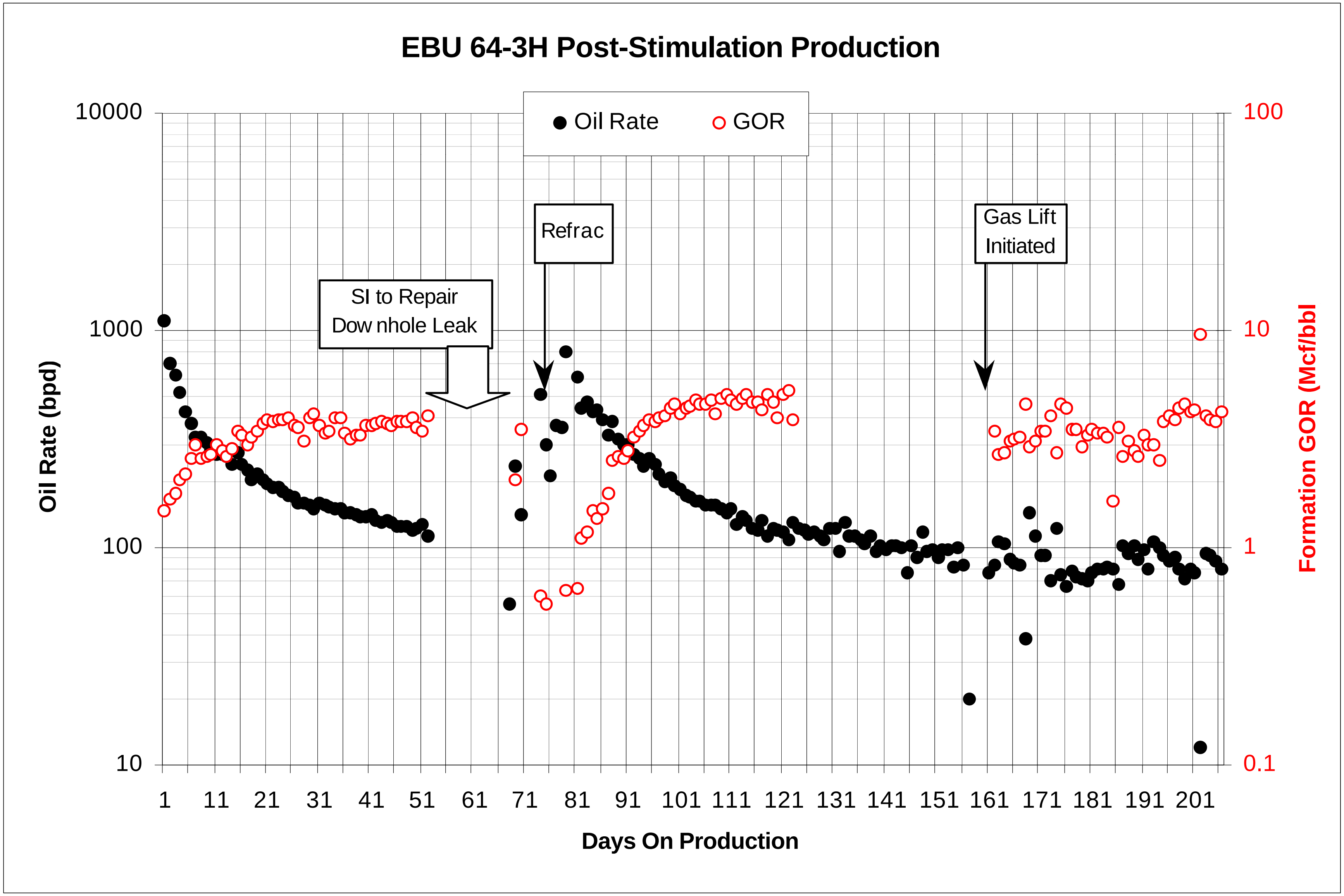

Figure 4. Production data for horizontal well EBU 64-3H.

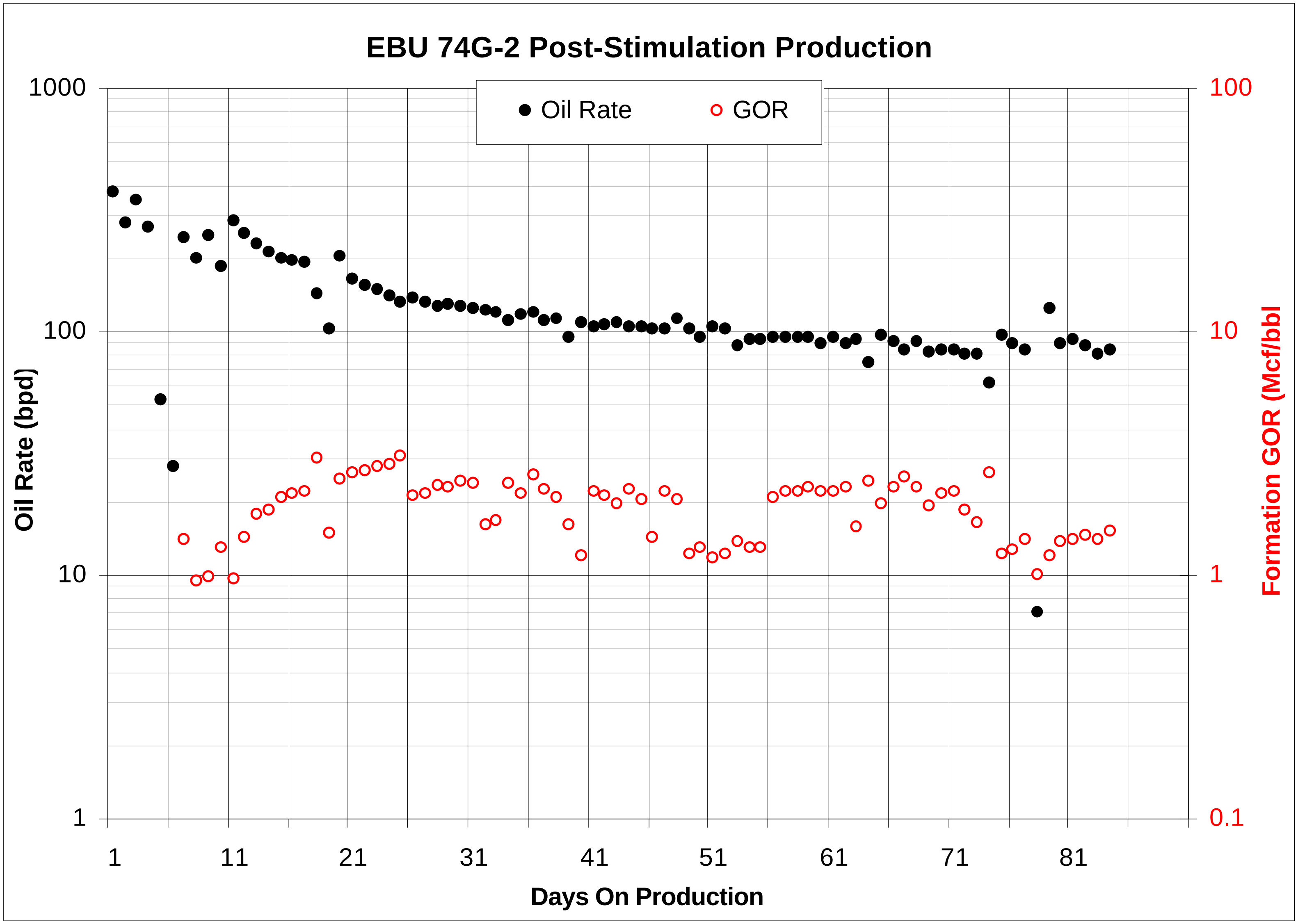

Figure 5. Production data for well EBU 74G-2.

East Binger Unit Pilot Area
Nitrogen Content in Produced Gas
1st Quarter 2003 Sample Data

Well	December 2001 Sample	3rd Qtr 2002 Sample	4th Qtr 2002 Sample	**1st Qtr 2003 Sample**
35-2	58%	-	61%	**-**
36-1	65%	50%	49%	**46%**
36-2	25%	-	29%	**-**
37-2	83%	77%	79%	**80%**
37-3H	68%	69%	67%	**69%**
43-1	9%	10%	-	**7%**
44-1	69%	67%	67%	**68%**
45-2	56%	58%	-	**57%**
46-2	62%	-	-	**68%**
48-1	83%	83%	84%	**84%**
57-2	37%	41%	39%	**41%**
58-2	8%	5%	-	**6%**
59-1	85%	-	-	**85%**
59-2	44%	-	-	**48%**
64-3H	-	23%	18%	**17%**
73-1	13%	21%	-	**21%**
74G-2	-	-	-	**6% - 10%**

Figure 6. Pilot Area gas sample data.

East Binger Unit
Reservoir Simulation Study
Results of Predictive Cases

		Incremental Gross Reserves					5-Year		Incremental Net Present Value		
Case	**Description**	**Oil (MBO)**	**NGL (Mbbls)**	**Methane (MMcf)**	**BOE (Mbbls)**	**Capital Investment ($M)**	**Cumulative Cash Flow ($M)**	**Investment Payout (Years)**	**Undisc. ($M)**	**10% Disc ($M)**	**20% Disc ($M)**
1	Convert 37-3H	280	48	(813)	193	$ 30	$ 400	4.0	1,042	807	365
2	Convert 44-1	120	6	(766)	(2)	$ 90	$ 422	2.4	(1,101)	(88)	62

Product Prices for Economic Evaluations

Oil	$25.00 / bbl (flat)
NGL	$17.00 / bbl (flat)
Gas	$3.00 / mcf (flat)

Figure 7. Comparison of simulation results – injection conversion cases.

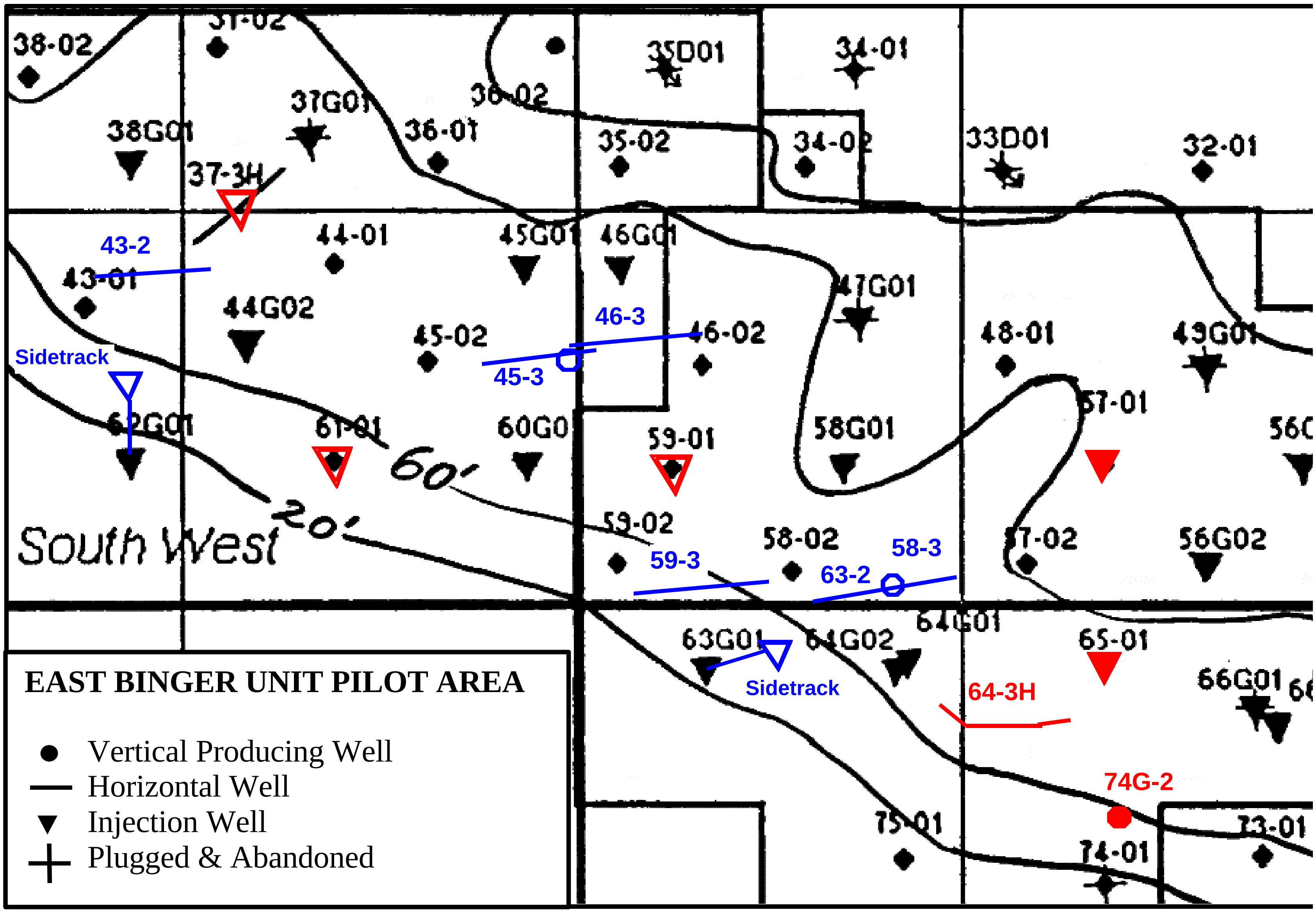

Figure 8. Potential drilling locations – shown in blue – evaluated with the simulation model. Items in red are either planned or completed.

East Binger Unit
Reservoir Simulation Study
Results of Predictive Cases

Case	Description	Incremental Gross Reserves Oil (MBO)	NGL (Mbbls)	Methane (MMcf)	BOE (Mbbls)	Capital Investment ($M)	5-Year Cumulative Cash Flow ($M)	Investment Payout (Years)	Incremental Net Present Value Undisc. ($M)	10% Disc ($M)	20% Disc ($M)
3c	Add 45-3H	(12)	69	123	77	$ 1,800	$ 397	1.7	$ (1,287)	$ (437)	$ (121)
3e	Add 46-3H	3	155	636	264	$ 1,800	$ 1,873	1.3	$ 2,533	$ 1,416	$ 1,095
3f	Add 45-3 (V)	18	94	361	172	$ 850	$ 1,049	1.5	$ 2,082	$ 843	$ 597
4c	Add 43-2H, ST 62G-1	75	129	783	334	$ 2,300	$ 935	2.9	$ 2,769	$ 928	$ 353
4d	Add 43-2H	4	117	345	178	$ 1,800	$ 1,399	2.1	$ 2,116	$ 979	$ 631
5c	Add 59-3H, ST 63G-1	77	104	660	291	$ 2,300	$ 977	2.1	$ 1,787	$ 848	$ 487
6c	Add 63-2H, ST 63G-1	140	102	665	353	$ 2,300	$ 1,794	1.8	$ 3,030	$ 1,580	$ 1,034
6d	Add 63-2H	31	186	878	364	$ 1,800	$ 2,281	1.5	$ 3,991	$ 2,143	$ 1,487
6e	Add 58-3(V), ST 63G-1	183	168	770	479	$ 1,350	$ 2,433	1.7	$ 6,937	$ 3,011	$ 1,805

H = Horizontal
(V) = Vertical
ST = Sidetrack

Product Prices for Economic Evaluations

Oil	$25.00 / bbl	(flat)
NGL	$17.00 / bbl	(flat)
Gas	$3.00 / mcf	(flat)

Figure 9. Comparison of simulation results – infill drilling cases.