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DESIGN AND IMPLEMENTATION OF A CO_2 FLOOD UTILIZING ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL INJECTION WELLS IN A SHALLOW SHELF CARBONATE APPROACHING WATERFLOOD DEPLETION

Final Report for Budget Period II
July 1, 1996-July 2, 2001

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ABSTRACT

The purpose of this project was to economically design an optimum carbon dioxide (CO_2) flood for a mature waterflood nearing its economic abandonment. The original project utilized advanced reservoir characterization and CO_2 horizontal injection wells as the primary methods to redevelop the South Cowden Unit (SCU). The development plans; project implementation and reservoir management techniques were to be transferred to the public domain to assist in preventing premature abandonment of similar fields.

The Unit was a mature waterflood with water cut exceeding 95%. Oil must be mobilized through the use of a miscible or near-miscible fluid to recover significant additional reserves. Also, because the unit was relatively small, it did not have the benefit of economies of scale inherent in normal larger scale projects. Thus, new and innovative methods were required to reduce investment and operating costs.

Two primary methods used to accomplish improved economics were use of reservoir characterization to restrict the flood to the higher quality rock in the unit and use of horizontal injection wells to cut investment and operating costs.

The project consisted of two budget phases. Budget Phase I started in June 1994 and ended late June 1996. In this phase Reservoir Analysis, Characterization Tasks and Advanced Technology Definition Tasks were completed. Completion enabled the project to be designed, evaluated, and an Authority for Expenditure (AFE) for project implementation submitted to working interest owners for approval. Budget Phase II consisted of the implementation and execution of the project in the field. Phase II was completed in July 2001.

Performance monitoring, during Phase II, by mid 1998 identified the majority of producing wells which under performed their anticipated withdrawal rates. Newly drilled and re-activated wells had lower offtake rates than originally forecasted. As a result of poor offtake, higher reservoir pressure was a concern for the project as it limited CO_2 injectivity. To reduce voidage balance, and reservoir pressure, a disposal well was therefore drilled. Several injection surveys indicated the CO_2 injection wells had severe conformance issues.

After close monitoring of the project to the end of 1999, it was evident the project would not recover the anticipated tertiary reserves. The main reasons for under-performance were poor in zone CO_2 injection into the upper San Andres layers, poorer offtake rates from newly drilled replacement wells and a higher than required reservoir pressure.

After discussion internally within Phillips, externally with the Department of Energy (DOE) and SCU partners, a redevelopment of South Cowden was agreed upon to commence in year 2000. The redevelopment essentially abandoned the original development for Budget Phase II in favor of a revised approach. This involved conformance techniques to resolve out of zone CO_2 injection and use of horizontal wells to improve in zone injectivity and productivity.

A phased approach was used to ensure short radius lateral drilling could be implemented effectively at South Cowden. This involved monitoring drilling operations and then production response to determine if larger investments during the second phase were justified.

Redevelopment Phase 1 was completed in May 2000. It was deemed a success in regard to finding suitable/cost-effective technology for drilling horizontal laterals and finding a technique that could sustain long-term productivity from the upper layers of the San Andres reservoir. Four existing vertical producing wells were isolated from their existing completions and sidetracked with horizontal laterals into the upper layers of the San Andres. Overall average offtake rates for the four wells increased by a factor of 12 during the first four months after completion of Phase 1.

Phillips presented Phase 1 results to both the DOE and SCU partners. All parties agreed to continue with the Redevelopment Phase 2 activities.

Phase 2 of the redevelopment focused on current CO_2 vertical injection wells. Techniques were applied to resolve near well conformance concerns and then either single or dual laterals were drilled in the upper layers. Additional work required conformance resolution with a horizontal injection well and additional lateral drilling from four existing producing wells. Although Phase 1 had provided a short-term boost to lease offtake, it was Phase 2, by ensuring in zone CO_2 injection in all existing vertical wells, which would provide the longer-term reserve recovery from the upper San Andres.

Phase 2 activities commenced in October 2000 with drilling a single lateral in an existing CO_2 injector. Four dual lateral and one single lateral CO_2 injection wells were completed from existing wellbores to replace the poorly performing CO_2 vertical injection wells. Four additional single laterals from existing vertical production wells were also completed. Phase 2 was completed in April 2001.

Injection and production rates have been only partially successful in reaching project goals. Though confining injection in the pay zone has been achieved, total actual injection rate has been less that forecasted. All current CO_2 injection is via horizontal wellbores. Oil production volume, after peaking at near 710 barrels of oil per day (BOPD) in June 2001, has stabilized near 650 BOPD as of June 2002.

Appendix D, Monitoring Flood Performance, contains production and injection performance summaries.

INTRODUCTION

The cooperative agreement signed in June 1994 by Phillips Petroleum Company and the Department of Energy (DOE) requires two Topical Reports to establish a minimum dataset and data collection for this Class II activity.

The first report discusses Budget Period I, which covered General Information; 3-D Reservoir Description; Field Development History; Field Production Constraints and Design Logic; Evaluation of Cost-Share Project Results; Supporting Data; and Environmental Information. Budget Period I was completed on June 30, 1996.

The second Topical Report discusses Budget Period II, which covers field implementation. The report presented here fulfills the requirement for the second Topical Report.

Summary of Project Objectives

The principal objective of this project was to demonstrate the economic viability and widespread applicability of an innovative reservoir management and carbon dioxide (CO_2) flood project development approach for improving CO_2 flood project economics in shallow shelf carbonate (SSC) reservoirs.

Most of the incremental tertiary oil production from CO_2 projects in SSC reservoirs to date comes from a few, very large-scale projects where sizable economies of scale inherent in this type of development can greatly improve project economics. The five largest CO_2 miscible flood projects implemented in SSC reservoirs, up to 1992, accounted for over one-half of the total incremental oil production attributable to CO_2 miscible flooding in the United States.

This project was implemented to demonstrate the economic viability of advanced technology for developing a CO_2 flood project utilizing multiple horizontal CO_2 injection wells. The use of several horizontal injection wells drilled from a centralized location reduced the number and expense of new injection wells, wellheads, and equipment. It allows concentration of the surface reinjection facilities; and minimizes the costs associated with CO_2 distribution system.

It was anticipated the proposed advanced technology would show improved CO_2 sweep efficiency and significantly reduce capital investment to implement a CO_2 tertiary recovery project. This technology could then be readily transferred to the domestic oil industry and introduce CO_2 flooding as an economically viable technology for smaller SSC reservoirs and for independent operators.

Summary of Field Details

The South Cowden Unit is located in Ector County, Texas and produces primarily from the Grayburg and San Andres Formations of Permian Age. These formations were deposited in shallow shelf carbonate (SSC) environments along the eastern margin of the Central Basin

Platform. The primary target for CO_2 flood development for the project was a 150-200 foot gross interval within the Upper San Andres located at an average depth of approximately 4550 feet. The original oil in place (OOIP) for the South Cowden Unit is estimated to be 180 million barrels. The field was discovered in 1940 and unitized for secondary recovery operations beginning in 1965.

The Unit was nearing its economic limit in 1995, producing 342 barrels of oil per day (BOPD) at a watercut in excess of 95% from 42 active producers and 15 active water injectors. Ultimate recovery for primary plus secondary was estimated at 35 million stock tank barrels of oil (STBO), or approximately 20 percent of OOIP. Tertiary oil resulting from the CO_2 project was estimated at 12 million STB, or 8% within the project area.

Project Description

The South Cowden Unit (SCU) is an example of a very mature waterflood, rapidly approaching its economic limit. Past waterflood performance was considered good; however, field average watercut at the project start-up exceeded 95 percent, leaving tertiary recovery as the only remaining prospect for extending the field life and recovering the remaining oil. Advanced reservoir characterization was used to define the best areas/reservoir within the field, which are likely to perform well under CO_2 operations. Appendix A contains information on reservoir characterization.

Standard methods of CO_2 flooding were not viable under the 1996/1997 oil price scenarios due to the limited aerial extent of the lease. Standard methods included the traditional nine - or five-spot patterns. A feasibility study, in which the field was CO_2 flooded with 20-acre five-spots, indicated South Cowden Unit was an excellent technical CO_2 flood candidate. The large capital investment, however, restricted its economic viability. New and innovative methods were required to reduce overall investment to improve economic viability. These new methods, however, carried additional risk.

The innovative approach chosen was to CO_2 flood South Cowden Unit through multiple horizontal injection wells from a centralized location. Preliminary studies indicated significant cost reduction could be realized through lower overall drilling costs, reduced surface injection line requirements and operating costs reductions through re-injection cost reduction.

Improved sweep efficiency from the horizontal injection wells were expected to result in increased oil recoveries. Increased technical risks included injection distribution along the horizontal section of horizontal wells and overall vertical coverage within the horizontal well. Contingency plans for dealing with the technical risks were also developed. Advanced reservoir characterization was deemed essential to optimize the final project design.

At the conclusion of the project, a complete methodology for economical tertiary flooding of small SSC reservoirs will be established, allowing other operators to implement similar strategies for their own fields.

Summary of Budget Phase I

Work on the project was initiated in June of 1994 with the Reservoir Analysis and Characterization Task, which were used to develop a three-dimensional (3-D) geologic reservoir description. An adequate reservoir description was assembled in early 1995 to initiate simulation studies for project design and performance forecasting.

The second major step in the process was defining the Advanced Technology Definition Task. This task was divided into seven subtasks, including Special Laboratory Studies; Screening Studies to Identify Suitable Gelled Polymers for Profile Modification; Advanced Geostatistical Studies; Reservoir Simulation for Project Design and Performance Forecasting; Design of the Horizontal Well Scheme and the Final Project Development Plan; Design of Upgrades and/or Additions to Production, Water Injection, CO_2 Injection, Compression, Water Disposal, Automation, Electrical and Cathodic Protection Facilities; and Investment Cost Forecast, Operating Cost Forecast and generation of the Authority for Expenditure (AFE).

The AFE was approved and field implementation of the project (Budget Phase II) began in late October of 1995. From late October 1995, through June 30, 1996, work included in Budget Phase I was being finished-up while implementation work included in Budget Phase II was being done.

Objectives for Budget Phase II

Budget Phase II objective was to implement the original project development at the lease. Facilities were to be installed, several new wells drilled and several wells re-activated or abandoned. Geological and Reservoir modeling was to be revised based on new well data and production response from the lease. Details of the original project development are included in the Topical Report for Budget Phase I, and are summarized below.

EXECUTIVE SUMMARY

Use of horizontal laterals in a small carbon dioxide (CO_2) flood for both injectors and producers has been proven to be a technically feasible concept. The economic justification for use of horizontal laterals for CO_2 flooding has not yet been demonstrated. Because the CO_2 injection is progressing so slowly, longer-term oil production response, water-oil ratio (WOR), and gas-oil ratio (GOR) data will be required to make a definitive statement on the economic success or failure. The original forecasted oil production rates have not been realized primarily due to failure to maintain the CO_2 injection rate and restrict the injected CO_2 to the target zones. Based on current data, projects of similar net pay, permeability, injection rates and capital development costs are not likely to be economically feasible with crude oil price of $20 to $22 per barrel.

The original tertiary oil recovery base case forecasted was 10.4% of the 86.5 million barrels of oil (MMBO) original oil-in-place (OOIP) within the project area, or 9.0 MMBO. Tertiary recovery is now estimated to be 3.7 MMBO, or 4.3% of OOIP within the project area. Peak actual production rate to date was 718 barrels of oil per day (BOPD) in June 2001, and June 2002 production was 650 BOPD. The original forecasted peak rate (base case) was 1,750 BOPD in 2003.

In June of 1994, Phillips Petroleum Company received a financial award from the Department of Energy (DOE) to conduct a project in the South Cowden Unit (SCU) in Ector County, Texas. The purpose of the project was to design an optimum carbon dioxide (CO_2) flood project utilizing advanced reservoir characterization and CO_2 horizontal injection wells, demonstrate the performance of this project in the field and transfer the information to the public to avoid premature abandonment of other fields.

The Unit's producibility problem was that it was a mature waterflood with water cut exceeding 95%. Oil must be mobilized through the use of a miscible or near-miscible fluid to recover significant additional reserves. Also, because the unit was relatively small, it did not have the benefit of economies of scale inherent in normal larger scale projects. Thus, new and innovative methods were required to reduce investment and operating costs.

Two primary methods used to accomplish improved economics were use of reservoir characterization to identify and restrict the flood to the higher quality rock in the unit and use of horizontal injection wells to cut investment and operating costs.

The project consisted of two budget phases. Budget Phase I started in June 1994 and ended late June 1996. In this phase Reservoir Analysis, Characterization Tasks and Advanced Technology Definition Tasks were completed. Completion enabled the project to be designed, evaluated, and an Authority for Expenditure (AFE) for project implementation submitted to working interest owners for approval. Budget Phase II consisted of the implementation and execution of the project in the field. Phase II terminated in July 2001.

Budget Phase I included preparing geological and petrophysical interpretive data in a stratigraphic framework. This was subsequently incorporated into full-field simulation to evaluate various combinations of horizontal and vertical CO_2 water alternating gas (WAG) injection wells.

Preliminary studies were conducted to investigate the effect of CO_2 WAG injection strategy on project performance. A hybrid WAG injection scheme was determined as the optimum project design. Performance forecasts were generated for the base case project development plan, with an incremental oil forecast estimated at 10.4% of OOIP. The full-field simulator was used to assess the effect of uncertainties in key input and operating parameters on the production profile and recoverable reserves for use in project risk analysis.

Budget Phase II commenced with the drilling of the third reservoir characterization well (RC-3, later re-named 6-24) during November and December 1995. Well logs indicated reduced porosity in the E and F zones, compared with offset wells. The well was perforated and tested 100% water, and temporarily abandoned.

Two vertical CO_2 WAG injection wells (2-26 and 2-27) were drilled during December 1995. SCU 2-27 was temporarily completed as a producing well until injection facilities were completed. SCU 2-26 was completed as a CO_2 injection well upon completion of the injection facilities.

Two additional production wells (SCU 6-22 and SCU 7-12) were also drilled and completed in late 1995. These wells were needed to drain areas of the field offsetting the proposed horizontal injection wells, replacing old wells previously plugged and abandoned.

Two horizontal CO_2 WAG injection wells (6C25H and 7C11H) were drilled and completed during March and April 1996 respectively. The wells were designed to mechanically optimize well injection performance and useful well life.

Initiation of CO_2 injection commenced in the summer of 1996 in two vertical WAG injection wells (2-26/2–27) and two horizontal WAG injection wells (6C25H/7C11H), at a rate of approximately 8.0 million standard cubic feet per day (MMSCFD) within the SCU project area. Three additional leaseline WAG injection wells were drilled in late 1996 and completed along the north boundary with the Emmons Unit. Injection profile problems were identified during early 1997 in these wells. Subsequent foamed cement isolation techniques during 1997 reduced out-of zone injection in these wells.

Two additional production wells were drilled during late 1996. SCU 7-13 as a replacement well and SCU 7-15 to tighten the spacing in an important area of the Unit.

An additional replacement Well No. 6-29 was drilled in September 1997, to replace Well No. 6-01, which had irreparable casing damage. Two shut in producing wells, 6-18 and 8-03, were converted to water injection during third quarter 1997. Three wells, 2-16W, 6-01 and 6-12, were plugged and abandoned due to regulatory requirements associated with bad casing.

Performance monitoring by mid 1998 identified the majority of producing wells under performed their anticipated withdrawal rates. Newly drilled and re-activated wells had lower offtake rates than originally forecasted. Although acid stimulations and individual "designer" well chemical treatments during 1997 improved productivity, they were somewhat short lived. A longer-term solution was needed.

As a result of poor offtake, higher reservoir pressure was a concern for the project as it limited CO_2 injectivity. To lower reservoir pressure, improving withdrawal rates became of utmost priority with various solutions evaluated: chemical treatments, perforations, stimulation and horizontal lateral technology. To reduce voidage balance, water production was required off lease. Well 2-18 was therefore drilled as a water disposal well by deepening to the Canyon and/or Clearfork intervals and initially averaged 1793 barrels of water per day (BWPD).

CO_2 injection pressures were cut back in late 1997 to reduce pressures below fracture initiation pressure. It was believed initial over pressuring during the early months of injection caused significant out of zone injection. Technologies were evaluated to improve injectivity in-zone to ensure CO_2 volumes were efficiently utilized.

After close monitoring of the project to the end of 1999, it was becoming clear that the project would not recover the anticipated CO_2 reserves. The main reasons for under-performance were poor in-zone CO_2 injection into the upper San Andres layers, poorer offtake rates from newly drilled replacement wells and a higher than required reservoir pre ssure.

A revised simulation model was built during 1996, after incorporating newly drilled well data. This was updated to history match the CO_2 flood performance during 1997, 1998 and 1999. The overall field wide average "in-zone" CO_2 injection was estimated at 55%, with the majority of in-zone injection entering horizontal well 6C25H, with little or no in-zone injection in any other of the six CO_2 injection wells.

After discussion internally within Phillips, externally with the Department Of Energy and SCU partners, a redevelopment of South Cowden was agreed upon to commence in year 2000. The re-development essentially abandoned the original development for Budget Phase II in favor of using a revised approach. This involved conformance techniques to resolve out of zone CO_2 injection and use of horizontal wells to improve in-zone injectivity and productivity.

The redevelopment of South Cowden centered around short radius lateral drilling from existing vertical wells and selective vertical well stimulation in the upper San Andres. This was determined as the optimum redevelopment scheme to improve the CO_2 flood. The optimum redevelopment with regard to recovery and economics followed a two-phased approach.

REDEVELOPMENT PHASE I:	Test lateral technology, improve production rate in center of CO_2 flood.
REDEVELOPMENT PHASE II:	Improve in zone injection and reduce reservoir pressure.

The phased approach ensured short radius lateral drilling could be implemented effectively at South Cowden. This involved monitoring drilling operations and then production response to determine if larger investments during the second phase were justified.

Phase I was completed in May 2000. It was deemed a success in regard to finding suitable/cost-effective technology for drilling horizontal laterals and finding a technique that could sustain long - term productivity from the upper layers of the San Andres reservoir. Four existing vertical producing wells 7-13, 6-23, 6-20 and 6-22 were isolated from their existing completions and side-tracked with horizontal laterals into the upper layers of the San Andres. Overall average offtake rates for the four wells increased by a factor of 12 during the first four months after completion of Phase 1.

Phillips presented Phase 1 results to both the DOE and SCU partners. All parties agreed to continue with the Phase 2 activities.

Prior to commencing Phase 2 activities, a selective stimulation method was attempted in two wells but did not prove successful. This technique was being considered for several wells as part of Phase 2 activities, but because of poor productivity improvements observed on these test wells, was abandoned in favor of additional lateral drilling.

Phase 2 of the redevelopment focused on current CO_2 vertical injection wells by resolving near well conformance concerns and either single or dual lateral drilling in the upper layers. Additional work required resolving of conformance issues with horizontal injection well 7C11H and additional lateral drilling in four existing pr oducing wells.

Although Phase 1 had provided a short-term boost to lease offtake, it was Phase 2, by ensuring in zone CO_2 injection in all existing vertical wells, which would provide the longer-term reserve recovery from the upper San Andres.

Phase 2 activities commenced in October 2000 with drilling a single lateral in well 2-27 CO_2 injector. It was originally anticipated to complete the Phase 2 work before year-end 2000 to ensure completion of Budget Phase II, as premised with the DOE agreement. At th is time rig availability became an issue and a second/third rig could not be obtained. As a result the DOE agreed to extend the closure of Budget Phase II to the end of the second quarter 2001, to allow completion of the project with a single rig.

Phase 2 was completed in April 2001. Wells 6-26, 6-27, 6-28 were completed on the Emmons/SCU leaseline with only minor near well conformance issues. Well 2-27 was drilled as a single 2300' lateral. This well had the most severe conformance issue encountered. It w as deemed to have hit an induced fracture about 350' from the existing surface location. The fracture was isolated with a foamed cement/permseal/flocheck technique. Well 2-27 has failed to achieve injection of CO_2 within the allowed surface pressure constraint.

In summary, Redevelopment Phase 1 was moderately successful, but Phase 2 has failed to achieve the desired injection and production results. ConocoPhillips intends to continue purchasing and injecting CO_2 along with produced CO_2 and will maintain water injection into the current injection wells, and maintain production operations so long as revenues justify the costs of operations. There are no current plans for any additional cap ital expenditures on the South Cowden Unit.

EXPERIMENTAL

None.

RESULTS AND DISCUSSIONS

Below is a comparison of the original project development for Budget Phase II and the actual implementation in the Unit.

Additional Surface Facilities details are provided in Appendix B.

Facilities Schedule of Work

Original Development Schedule	Actual	Comment
1995		
Purchase land and build fence	Mid 1996	
1996		
Construct injection facilities	Mid 1996	
Start battery modifications	Completed mid 1997	
Prepare for compression	Compression started Fall 1996	
Replace water injection system	Mid 1996	
Install cathodic protection	Fall 1996	Not required, after tests
Start automation installation	Completed Fall 1996	
1997		
Continue battery modifications	Completed mid 1997	
Start flow line replacement	Completed mid 1996	
Continue automation installation	Completed Fall 1996	
1998		
Finish battery modification	Completed mid 1997	
Continue flow line replacement	Completed mid 1996	
Upgrade compression		Not required at that time
Continue automation	Completed Fall 1996	Compr. upgraded in 2000
1999+		
Finish flow line replacement	Completed mid 1996	
Finish automation installation	Completed Fall 1996	

Additional drilling and well workover details are provided in Appendix C.

Well Work Schedule

Original Development Schedule	Actual	Comment
1995 Drill Well RC-3	Nov 1995	Named 6-24
1996 Drill Wells H-1 and H-2	Mar/Apr 1996	Named 7-11& 6-25
Drill vertical wag injector 2-06C	Dec 1995	Named 2-26
Drill two lease line vertical wag injectors 7-07 and M-17C	Late 1996	7-07 location (6-28) drilled but not funded by DOE, M-17C drilled and named 6-27
Equip 615W as wag injector	6-26 drilled late 1997	615W not converted to WAG well. (6-26 drilled as alternate funded by DOE).
Drill producing wells 7-98, 7-12, 6-22 and 7-99	end 1996	7-97 named 7-13, 7-99 named 7-15
Reactivate producers 705 and 620	end 1996	
Convert to water injection wells 2-21, 8-18, 8-03, 6-18 and 5-02	majority completed by early1997	2-21 not completed
1997 Reactivate 6-16W as leaseline water injector		Not completed
Reactivate producers 6-19, 7-02, 7-10 and 8-13	early 1997	
Drill vertical wag injector 208C	late 1995	Named 2-27
1998 Drill producing wells 2-03A	6-99 mid 1997	2-03A not completed.

And 6-99	6-99 named 6-29
Reactivate producers 2-20 and 6-05 2-20 early 1997	6-05 not re-activated
1999+ Drill four replacement producers (locations to be determined)	not completed
Convert to wag injection: RC3 And 2-24C	not completed

Chronological Summary of Progress Budget Phase II – Field Demonstration

Below is a chronological breakdown of the original Budget Phase II development, monitoring operations and redevelopment activities performed from 1996 through 2001.

To mid year 1996

Field Demonstration encompassed the project implementation subtasks, including drilling, testing, and completion of Reservoir Characterization Well RC-3; construction of carbon dioxide (CO_2) distribution center; construction of CO_2 recycle facilities; construction of centralized production and gathering center facilities; drilling two horizontal wells; drilling two water alternating gas (WAG) injection wells; drilling two vertical producers; commencing water injection into the horizontal wells and performance monitoring; and the evaluation of project performance.

To mid year 1997

Field Demonstration from mid 1996 to mid 1997 encompassed injection testing and initiation in horizontal injection Wells Nos. 6C25H and 7C11H along with vertical injection Wells Nos. 2-26W and 2-27W; the drilling/testing of three replacement leaseline WAG injection wells and two production wells; the conversion of three wells for water injection; the reactivation of seven shut-in wells for production; the remediation of nine existing production wells; the purchase of CO_2; the operation of the recycle compression and injection facilities; and the monitoring of project performance. Technology transfer, reporting and project management related to Budget Phase II primarily included media opportunities related to the project start-up, preparation of technical papers, and participation in industry events and the 1997 Department of Energy (DOE) project review.

To mid year 1999

Field Demonstration from mid 1997 to mid 1999 encompassed drilling a vertical producer; converting two wells to water injection; remediation of fourteen producers; plugging and abandonment of two wells and monitoring of project performance.

Monitoring revealed several concerns, which were being evaluated at that time. One main concern was the lack of productivity from wells. The wells in question were the newly drilled wells and re-activated wells. Both types had not seen the same level of productivity expected from plugged and abandoned offset wells that the new wells were drilled to replace.

Cleanouts and acid stimulations during 1997 proved moderately successful in treating this problem, but did not provide a long-term solution. More success was achieved with a chemical treatment program specifically designed for each well after analysis of fluids and solids being produced at surface. These "designer" chemical treatments proved fairly successful on all wells treated, but again did not provide the level of long-term productivity expected from the original offsets wells.

Also under review, were some new methods of improving productivity using horizontal lateral technology. If this proved successful it would provide an extremely cost effective approach for improving offtake rates.

Monitoring of CO_2 response suggested areas with high CO_2 injectivity, which was in-zone, provided the best response to surrounding producing wells. Other areas of the field that suffered from poor injectivity due to high reservoir pressure and/or large out of zone CO_2 injection did not provide much incremental oil productivity. The forward management plan in mid 1999 was to improve these problems with some innovative and cost effective technologies.

To mid year 2000

After close monitoring of the project to the end of 1999, it was becoming clear the project was not producing at the required oil rates and was in danger of not recovering the anticipated tertiary reserves. The main reasons for under-performance were poor "in-zone" CO_2 injection in the upper San Andres layers, poor offtake rates from newly drilled replacement wells and a high reservoir pressure.

A revised simulation model was built during 1996, after incorporating newly drilled well data. This was updated to history match the CO_2 flood performance during 1997, 1998 and 1999. The overall field wide average "in-zone" CO_2 injection was estimated at 55% with the majority of in-zone injection entering horizontal well 6C25H, with little or no in-zone injection in any other of the six CO_2 injection wells.

After discussion internally within Phillips, externally with the Department Of Energy (DOE) and South Cowden Unit (SCU) partners, a redevelopment of South Cowden was agreed upon to commence in year 2000. The redevelopment essentially abandoned the original development for Budget Phase II in favor of using a revised approach using conformance techniques to resolve out of zone CO_2 injection in the near well area and use of horizontal wells to improve in-zone injectivity/productivity.

The redevelopment of South Cowden centered around short radius lateral drilling from existing vertical wells and selective vertical well stimulation in the upper San Andres. This was determined as the optimum redevelopment scheme to improve the CO_2 flood. The optimum redevelopment with regard to recovery and economics followed a two-phased approach.

REDEVELOPMENT PHASE I: Test lateral technology, improve offtake in center of CO_2 flood.

REDEVELOPMENT PHASE II: Improve in-zone injection and reduce reservoir pressure.

The phased approach ensured short radius lateral drilling could be implemented effectively at South Cowden. This involved monitoring Phase I drilling operations and production response to determine if larger investments during the second phase were justified.

Phase I was completed in May 2000. It was deemed a success in regard to finding suitable/cost-effective technology for drilling horizontal laterals and finding a technique that could sustain long-term productivity from the upper layers of the San Andres reservoir. Four existing vertical producing wells 7-13, 6-23, 6-20 and 6-22 were isolated from their existing completions and side-tracked with horizontal laterals into the upper layers of the San Andres. Overall average offtake rates for the four wells increased by a factor of 12 during the first 4 months after completion of Phase 1.

Phillips presented Redevelopment Phase 1 results to both the DOE and SCU partners. All parties agreed to continue with the Redevelopment Phase 2 activities.

To mid year 2002

Prior to commencing Redevelopment Phase 2 activities, a selective re-perforating/stimulation method was attempted in September 2000 in two wells that did not prove successful. This technique was being considered for several wells as part of Phase 2 activities, but because of poor productivity improvements observed on these test wells, was abandoned in favor of additional lateral drilling.

Phase 2 of the redevelopment focused on CO_2 vertical injection wells with resolving near well conformance concerns and either single or dual lateral drilling in the upper layers. Additional work involved resolving of conformance issues with horizontal injection well 7C11H and additional lateral drilling in four existing producing wells.

Although Phase 1 had provided a short-term boost to lease offtake, it was Phase 2, by ensuring in zone CO_2 injection in all existing vertical wells, which would provide the longer-term reserve recovery from the upper San Andres.

Phase 2 activities commenced in October 2000 with a single lateral drill in well 2-27. It was originally anticipated to complete the Phase 2 work before year-end 2000 to ensure completion of

Budget Phase II, as premised with the DOE agreement. At this time rig availability became an issue and a second/third rig could not be obtained. As a result the DOE agreed to extend the closure of Budget Phase II to the end of the second quarter 2001, to allow completion of the project with a single rig.

Phase 2 was completed in April 2001. Wells 6-26, 6-27, and 6-28 were completed on the Emmons/SCU leaseline with only minor near well conformance issues. Well 2-27 was deemed to have hit an induced fracture about 350' from the existing surface location. The fracture was successfully isolated with a foamed cement/permseal/flocheck technique; prior to reaching the 2-27 planned total depth (TD).

Facilities Installation

Budget Phase II required surface facilities upgrades to handle the CO_2 processing from the development. A 13-mile pipeline was installed to transport CO_2 to South Cowden from the Central Basin CO_2 supply line. A CO_2 re-cycle compression facility was installed to handle up to 8.6 MMSCF/D (after upgrades). Injection lines were installed to each CO_2 well. A WAG injection manifold was installed to centralize distribution of injectant. A new Tract 6 satellite production facility was installed to deal with increased CO_2 production. Water injection distribution pipelines were upgraded. Modern metering and safety monitors were installed. The purchasing of some private lots in the southern part of the lease reduced costs associated with rights of way and injection line installation. Details of the facility installation are found in Appendix B.

Drilling and Workover

Budget Phase II activities followed the original project development plan to 1999. This included drilling several new wells, re-activating others, and conversions to water injection.

In addition to the original development plan, work was implemented between 1997 and 1999 where several wells were worked-over to improve productivity and injectivity. Producing wells were acid stimulated to improve offtake and several CO_2 vertical injection wells were worked over to improve in-zone injectivity.

Overall these additional activities did not prove successful in improving CO_2 processing in the Upper San Andres. This led to a cessation of the original development plan while alternative developments were evaluated, which eventually led to the Year 2000 redevelopment where CO_2 processing was improved through use of lateral and conformance technologies.

Details of the Drilling and workover activities are found in Appendix C.

Flood Monitoring

Monitoring of production data, to the end of 1999, indicated the area around horizontal injection well 6C25H had the best response to CO_2. Suggesting areas where zonal isolation of injected CO_2 into the zone of interest, and high injectivity was possible, would have the greatest benefit from CO_2 injection.

Well 6C25H was drilled horizontally into the zone of interest, and had no indications of out of zone injection, unlike its twin well 7C11H, where a perceived fracture system was taking the majority of injected gas. Response from nearest well to the toe of 7Cl1H suggested it was also responding to CO_2, so some percentage of the injected CO_2 was entering the zone of interest. The majority, however, appeared to enter a fracture system and into the out of zone layers.

Other areas of the field, such as around vertical injection wells 2-27, 2-26, 6-26, and 6-27 had little or no response, suggesting the out of zone CO_2 injection associated with these wells was contributing to the poor CO_2 processing of the San Andres Upper layers.

The lack of well productivity was a major concern for the flood. The offtake rate from re-entered and replacement wells were lower than originally anticipated. This resulted in a voidage in -balance in the field where productivity was not able to match injectivity.

This led to a general rising of reservoir pressure during the ea rly months of CO_2 injection, to levels close to fracture initiation pressure. The high reservoir pressure limited CO_2 injection where injection pressures were constrained less than fracture pressure. Conversely, in some wells, injection pressures were not constrained and induced out of zone CO_2 injection.

Several activities were performed to resolve the poor productivity from wells including acid stimulations, chemical treatments, jetting techniques and additional perforations. None of the techniques proved successful in providing a long-term productivity improvement, required to boost the offtake rate from the lease to lower reservoir pressure.

A disposal well, 2-18, was eventually deepened to the Clearfork interval and a high proportion of produced water was injected into the Canyon/Clearfork intervals. This aided lowering reservoir pressure by lowering voidage replacement ratio.

Overall, by the end of 1999, the lease was under-performing its predicted CO_2 response due to a combination of poor offtake, poor in-zone CO_2 injection, higher reservoir pressure and a fundamental belief that the original predictions for offtake were too optimistic.

Geological/Reservoir Model Update

Since Budget Phase I completion, additional well data and revised porosity/permeability relationships were incorporated into a new geological/reservoir model. The new model was completed in 1996. The work involved is discussed below. The original "AFE" model, used for

Budget Phase I, was therefore superceded in late 1996 with a new model to revise forecast predictions for Budget Phase II.

Visual inspection of the porosity/permeability distribution in the geologic model indicated the E zone interval (the primary target for carbon dioxide (CO_2) flooding) could be separated into four units, compared to three in the original "AFE" model. These flow units were distinguished by small variations in porosity/permeability that were somewhat correlatable between wells. These four layers in the E, in addition to the F layer, upper D layer, and C layer, comprised the seven flow units in the reservoir simulation model.

Maps of structure, thickness, average porosity, and geometric average permeability were extracted from the geologic model to the seven simulation layers.

The South Cowden full field geological and the subsequent simulation model were therefore updated for:

a) Inclusion of data from five additional wells drilled in the project area, and

b) Improvements in delineating the porosity and permeability distribution in the project area.

This was obtained by integrating production performance data into the three dimensional (3-D) geological modeling. The resulting simulation model grid was 54 x 54 x 7 (20,412 active cells). The revised field performance history match obtained using the updated geologic model resulted in significant improvements in individual well performance matches.

Full-field simulation runs were completed to evaluate various developments of horizontal and vertical CO_2 WAG injection wells. The most effective configuration was determined to be one in which horizontal CO_2 WAG injectors were positioned in down-structure locations (oriented approximately parallel to structural strike) in combination with vertical WAG injection wells in structurally higher locations. The simulation runs indicated vertical permeability restrictions in the lower reservoir would limit vertical distribution of injected CO_2 into lower intervals if horizontal injection wells were used. Application of horizontal CO_2 injection wells was therefore effective in down-structure locations where the majority of reservoir pore volume lies below the original oil-water contact.

The initial revised model, discussed above, was completed in 1996. In subsequent years, during Budget Phase II, model updates were made annually to incorporate the exact project development and operating schedule. The model was adjusted to reflect the details of the actual locations, completions, and timing of newly drilled, reactivated, and recompleted wells in the CO_2 flood project area.

Of significant note was the productive capacity of several reactivated production wells. These were either new wells drilled immediately offsetting abandoned wells with poor casing integrity,

or wells re-entered in the mid 1990s that were previously temporarily abandoned. The new or re-entered wells were designed to increase offtake for the lease for the CO_2 project. Rates were initially significantly less than premised in the original forecasts (based on the productivity prior to shut-in or offset wells).

Overall "in-zone" injectivity throughout the lease averaged 55%. The majority of the "in zone" CO_2 injection being achieved in well 6C25H horizontal well, with little or no in zone injection in vertical CO_2 injection wells.

It was apparent the overall initial flood response had not been encouraging. Several wells were not injecting or producing as expected, resulting in a poor overall CO_2 response.

The history matched model, incorporating poorer producing well productivity, poor in zone injection and overall poor CO_2 processing and throughput in the Upper San Andres suggested that unless a significant redevelopment was undertaken to improve the flood the economics and tertiary reserves predicted would not be achieved.

Details of the model updating are found in Appendix E.

Original Development Issues and Redevelopment Summary

Out Of Zone Injection

The San Andres intervals were split into 7 layers (A, B, C, D, E, F and G) as part of the reservoir characterization performed in the mid 1990's. The structure is tilted, so in some areas of South Cowden the majority of the San Andres is above the oil water contact (OWC) at –1800'sub sea, and in others below the contact. The CO_2 development team highlighted the need for injecting CO_2 in the upper layers, or the "in-zone" section of the San Andres where layers are above the original oil water contact.

A summary, as of January 2000, of vertical and horizontal well CO_2 conformance observed during CO_2 flood implementation is summarized below.

Vertical Injection Wells

There are a total of 6 vertical CO_2 injection wells in the South Cowden Unit.

Wells	Area	Comments
2-26	Tract 2	CO_2 entering perforations (perfs) in C to G zones, but channeling to below B zone.
2-27	Tract 2	CO_2 entering perforations primarily in B and C zone, but channeling to below B zone.

	Between Two Horiz Injectors, Tract 6.	Well currently a shut in producer with high CO_2 rates. Unknown conformance issues. The well will be converted to CO_2 injection at some future date.
6-26	Leaseline	CO_2 entering perfs in C zone, but channeling to below C zone.
6-27	Leaseline	CO_2 entering perfs in E zone, possibly a small channel below.
6-28	Leaseline	CO_2 entering perfs in D zone possibly channel below. Current lowest perfs need squeezing off (close to OWC). Well shut in since drilled.

Horizontal Wells

There are two horizontal injection wells in the South Cowden Unit.

Wells	Area	Comments
6C25H	Tract 6	Well drilled in E zone at target depth of 4689'TVD. Well length drilled in E zone approximately 1900'. Well injecting as predicted and "in-zone".
7C11H	Tract 7	Well drilled in E zone at target depth of 4672'TVD. Well length drilled in E zone approximately 1300'. Effective length of well taking CO_2 is 40'. Well injecting in "toe" of well, in some form of fracture plane, will require workover to resolve.

Overall, CO_2 conformance issues, as of January 2000, could be summarized as good in-zone injection in well 6C25H, poor injection in well 7C11H – likely out of zone, poor injection in leaseline wells – majority out of zone, poor injection in Tract 2 - lower layer dominated.

Productivity/Injectivity

Productivity of wells is one of the major concerns for a successful South Cowden CO_2 flood. The majority of wells had not performed as anticipated due to combinations of:

a) Optimistic estimates of new well productivity.
b) Having ineffective methods to stimulate San Andres upper layers.

The effect of lower offtake rates on overall flood performance has been

a) lower oil production
b) reservoir pressure 500 pounds per square inch (psi) higher than required
c) reduced CO_2 injection due to high reservoir pressure
d) reduced throughput and CO_2 processing

Productivity could be improved through use of various non-fracturing stimulation techniques which would either reduce wellbore skin factors, or could drill out away from current well locations, where skin damage and/or poorer quality rock exists. The two main techniques recommended for South Cowden were:

a) Short radius laterals
b) Stimgun perforating, followed by heated acid treatments

Redevelopment Schedule/Plan/Costs

The major keys to redeveloping South Cowden were as follows:

1) Develop a method to improve productivity and injectivity without allowing communication to lower San Andres intervals.

2) Reduce overall reservoir pressure to improve CO_2 injectivity.

3) Developing methods to eliminate long term out of zone injection.

4) Ensure productivity can be maintained throughout the remainder of field life.

The overall strategy recommended to accomplish a successful redevelopment was primarily through the use of horizontal lateral drilling. The use of this technology would help improve productivity and injectivity through contacting better quality rock, contacting unswept areas and bypassing near well damage.

Several redevelopment options were considered for South Cowden. The optimum development with regard to recovery and economics followed a two-phased approach.

PHASE I – Test Lateral Technology, Improve Offtake in Center of CO_2 Flood.

Upgrade compressor to 4.5 MMSCF/D
Drill 4 laterals early 2000 – Wells 6-20, 6-22, 6-23 and 7-13
Monitor performance (decide to proceed with Phase II)

PHASE II – Improve In Zone Injection and Reduce Reservoir Pressure

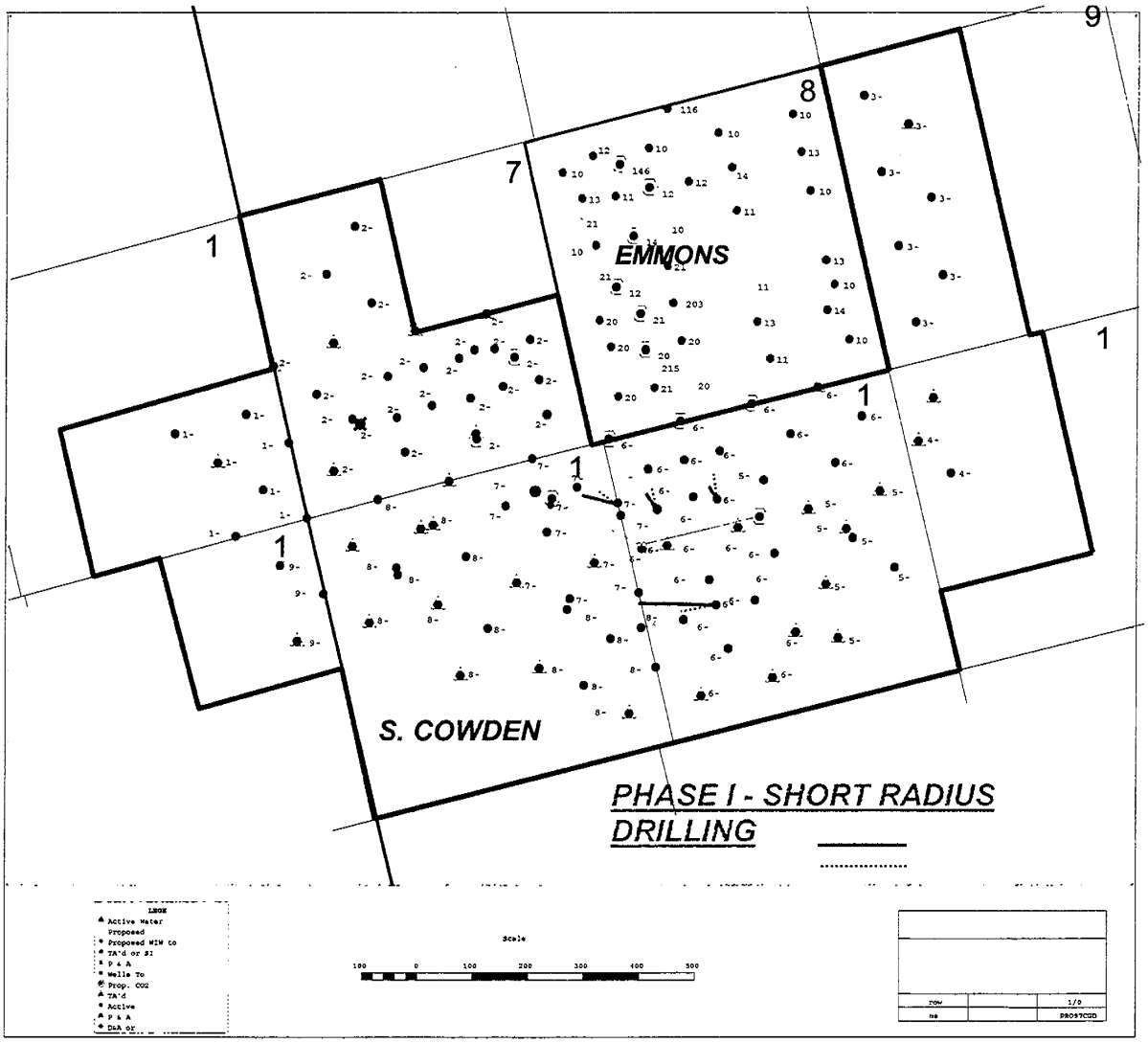
Improve injectivity in zone

Seal up wells 2-26, 2-27, 6-26, 6-27 and 6-28 in near well area and drill laterals
Improve Tract 2 productivity in zone
Test/Log/Stimtube/Hot Acid Wells 7-15, 7-12, 2-25, 2-24, 2-22, 2-21, 2-20, 2-17, 2-09, 2-08, 2-07 and 2-02.
Plug and Abandon (P&A) correctly 11 wells (some currently TA)
Relog Well 7C11H and resolve conformance.
Test Well 2-18D and upgrade to handle larger disposal rates.

The phased approach was used to ensure short radius lateral drilling could be implemented effectively at South Cowden. This involved monitoring drilling operations and production response to determine if larger investments during the second phase were justified.
Capital required for redevelopment was estimated at $2.8MM gross, with incremental recovery estimated at 4.65 MMSTB above un-developed CO_2 flood performance. Redevelopment operations were scheduled to commence in mid February 2000 with completion mid November 2000. Additional details are provided in Appendix G.

Year 2000 Redevelopment Phase 1 Results

Phase I was completed in May 2000. It was deemed a success in regard to finding suitable/cost-effective technology for drilling horizontal laterals and finding a technique that could sustain long - term productivity from the upper layers of the San Andres reservoir. Four existing vertical producing wells 7-13, 6-23, 6-20 and 6-22 were isolated from their existing completions and side-tracked with horizontal laterals into the upper layers of the San Andres. Overall average offtake rates for the four wells increased by a factor of 12 during the first four months after completion of Phase 1.



Several weeks of preparation work were involved prior to commencing Phase 1 activities. A Rotary steerable system was chosen initially as the lateral drilling technique. Phillips worked closely with the drilling contractor and also additional service companies to resolve as many up front and anticipated operational issues prior to commencing Phase 1.

Three out of the four wells required conformance work to seal up the existing vertical well. Injection logs revealed behind pipe and micro annulus tendencies. A combination of Flocheck and foamed cement proved effective at resolving these issues.

The majority of CO_2 injection was shut down in the lease prior to commencing Phase 1. During this time downhole pressure gauges were installed in the two horizontal CO_2 injectors. The

analysis revealed that 6C25H injectivity had essentially not changed since starting CO_2 injection. For the 7C11H, the horizontal injector with a known "toe-fracture", the analysis revealed the fracture was still present and had become easier to initiate since the last injection test performed in 1996. The analysis was also used to provide fracture dimensions for conformance work planned during Phase 2 Redevelopment. More information can be found in Appendix I - CO_2 Horizontal Well Test Analysis.

Lateral drilling commenced with 7-13 lateral in early March 2000. The lateral took just over 21 days to complete compared to 10 days or less originally anticipated. As a result drilling costs for the well were higher than anticipated. Prior to starting Phase 1 work, costs for each well was anticipated to be less than $150 M (if no serious conformance issues were encountered).

Preparation times, curve drilling time and straight section drilling all took longer than anticipated. This was related to poorer curve/straight section penetration rates, frequent drill-pipe "twist-off" with the resulting fishing operations, and poor directional stability resulting in changes in drill-pipe to correct trajectories.

The heated acid stimulation, using coiled tubing and hydrablast tool, went without incident, and proved operationally easy to accomplish on this and subsequent wells.

Well 6-23 was the next well in the program. Several changes were made to improve drilling times. Even with changes no dramatic improvement of penetration rates were realized. The well took a total of 18.5 days to drill to a 300 ft departure from the existing well. The fundamental problem was the poor penetration rates and time taken for preparation. Preparation work involved sectioning the casing, setting a cement plug and dressing the plug off to a kick off point.

6-20 was the third well in the program. The drilling contractor had agreed the previous penetration rates were not acceptable, and agreed to use a downhole motor system for the straight section. This, however, had poor directional control and required a trajectory change using the curved assembly from the rotary steerable system. The same fundamental problem of poor preparation and curved drilling duration still existed using this revised system, even though somewhat improved penetration rates had been realized with a downhole motor system in the straight section.

For the final well a different approach was taken using an alternate contractor's system. This had been used successfully on offset leases. The system was a four-stage process. Once the well is prepared a whipstock is installed, the casing is milled, and the curved section drilled with a mud motor. Finally the lateral section is drilled with a mud motor. Surveying is performed using a measurement while drilling (MWD) tool, typically taking 15 seconds to survey. Any corrections to direction/trajectory are performed downhole.

The new technique proved a success with 700' departure drilled after 6 days from the commencement of operations. As penetration rates were so good the contractor was asked to extend the length of the well out to 1500'. This was completed after an extra day and a half. If the

well had been completed with 700' the total cost was estimated under $150k. The drilling technique had therefore proven a 700'lateral could be drilled cost effectively at the lease, and the team was confident in applying the same technique for Phase 2 laterals.

Production monitoring through April 2000 to October 2000 was employed to evaluate the success of laterals to improve offtake from the lease.

7-13 vertical well, with a cased and perforated completion, produced at fluid rates of 13 barrels of fluid per day (BFPD) prior to the lateral drilling. The lateral averaged 181 BFPD through the monitoring period with an average oil production of 75 BOPD. This was an average 13-fold increase in productivity. Little or no productivity loss was observed.

6-23 vertical well produced at fluid rates of 78 BFPD prior to the lateral drilling. The lateral averaged 311 BFPD through the monitoring period with CO_2 response evident at the end. This was an average 4-fold increase in productivity. Little or no productivity loss was observed. This well was not drilled as anticipated with only 300 ft departure against the 630 ft planned, but still managed an acceptable productivity improvement.

6-20 vertical well produced at fluid rates of 56 BFPD prior to the lateral drilling. The lateral averaged 292 BFPD through the monitoring period with oil rates increasing to 90 BOPD at the end. This was an average 5-fold increase in productivity. Little or no productivity loss was observed.

6-22 vertical well produced at fluid rates of 56 BFPD prior to the lateral drilling. The lateral averaged 1485 BFPD through the monitoring period with no CO_2 response seen. The well was anticipated to take some time to respond to CO_2 injection due to the physical distance to the nearest CO_2 injector. This was an average 25-fold increase in productivity. Little or no productivity loss was observed.

Overall average offtake rates for the four wells increased by a factor of 12 during the first four months after completion of Phase 1.

The effect on the total lease was to increase offtake by an average of 27%, accelerating the lease productivity and the reduction in reservoir pressure. Total lease oil rates increased from a low of 400BOPD at the beginning of Phase 1, to a high of 575 BOPD at the end of the monitoring period.

Additional details are provided in Appendix J.

Year 2000 Redevelopment Phase 2 Preparation and Amendments

The basic original lateral design was to kick off in the Grayburg interval, in a tight Anhydritic interval above the San Andres. Then drill the curve section to the top of the F zone. Small Grayburg sands are evident in some areas of the field between the kick off points and the top of

the F zone. Therefore, after drilling to top F zone, Grayburg injectivity is tested (*see below). Then the straight section drilled to the final depth, normally in the mid D zone.

Cost estimates for Phase 2 activities were prepared under the assumption the near well areas, especially around lease line injection wells, would have severe behind pipe and near well fracturing requiring conformance techniques to resolve. The contractors and techniques used for Phase 2 were essentially a continuation of the successful methodology involved with the drilling of the last well of Phase 1, which was a proven success.

Two wells, 7-15 and 6-29, were used as test wells to determine if the Stimtube/Heated acid technique could be expanded to additional SCU wells. The technique was being evaluated to boost upper San Andres productivity without causing behind pipe communication paths to lower `San Andres zones. Both 7-15 and 6-29 stimgun/heated acid treatments were performed but productivity testing revealed no significant benefit of the technique. Although it appeared the technique did not induce communication paths to lower layers, the productivity of the wells had not changed or was reduced. Based on these results it was deemed necessary to start preliminary planning of additional producing laterals as an alternative technique for boosting upper layer productivity in the lease.

Horizontal well 7C11H required a conformance technique to prevent out of zone injection at the well's toe as part of Phase 2 activities. Halliburton d eveloped a procedure involving the use of their proprietary "Diamond Seal" product, which would be injected at surface, enter and seal the fracture system and then be washed out with coiled tubing (CT).

Preliminary fine scale modeling suggested little need for re-entering old abandoned wells, and work on abandoned wells was therefore taken out of Phase 2 activities. Fine scale modeling results are discussed in Appendix K.

Redevelopment Phase 2 Results

Phase 2A – Injectors

Existing vertical injector wellbores were plugged back, and were drilled as horizontal wellbores as follows during late 2000: 2-26W, 2-27W, 6-26W, 6-27W, 6-28W. Complete injection rate histories are included in the Appendix D "Monitoring Flood Performance". In summary, completions were successful in keeping injection "in-zone", and moderately successful in terms of achieving higher injection rate. Well 2-27W failed to achieve injection in-zone due to a large fracture encountered near the heel of the horizontal lateral. Sub sequent remedial work sealed the fracture, but also resulted in zero injection rates.

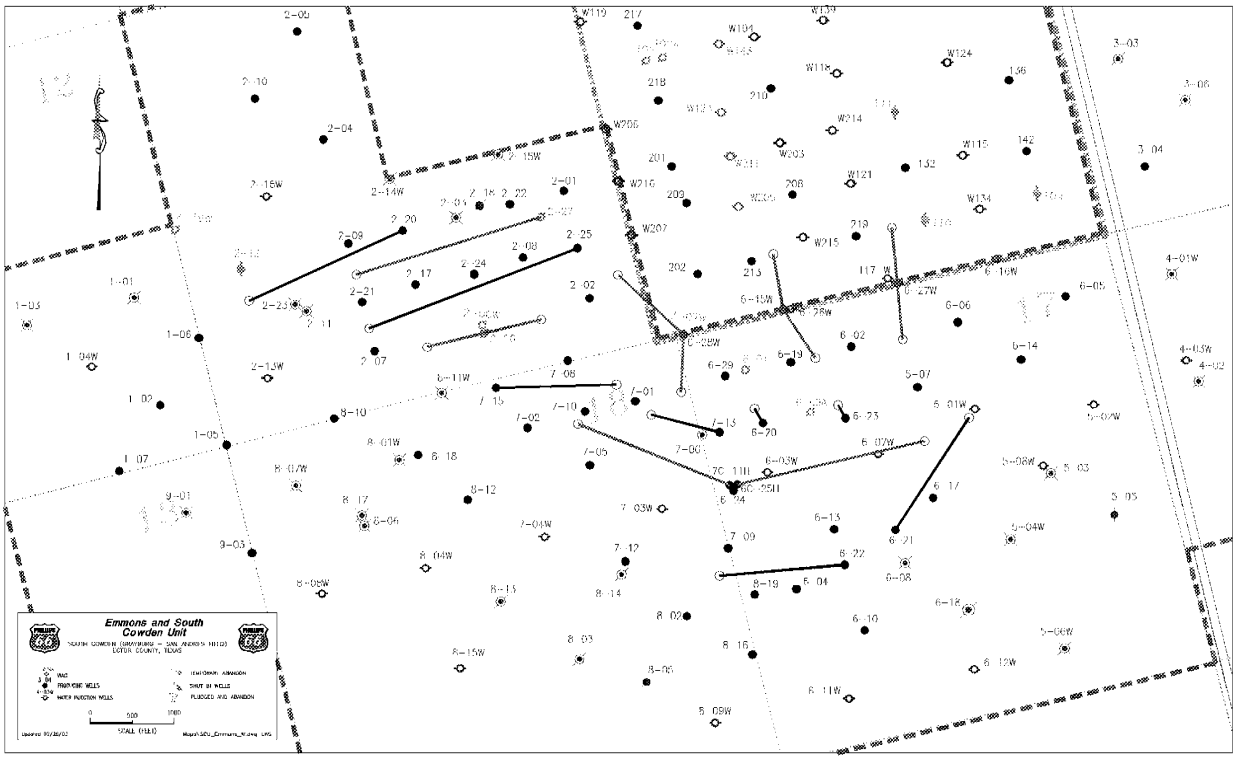
Phase 2B – Producers

Existing vertical producer wellbores were plugged back, and these wells were drilled as horizontal wellbores as follows in late 2000 and early 2001: 2-20, 2-25, 6-21, 7-15. Well 2-20 encountered

very poor permeability pay, and produces only 1 BOPD and 45 BWPD. The remaining wells have performed well.

Details of the Flood Monitoring activities are found in the Appendix D.

Below is a map of the South Cowden Unit at the completion of Phase 2. Horizontal CO_2 Injectors are shown as red lines, and horizontal producers are shown as black lines.



Fracture Modeling

Pinnacle Technologies were consulted to improve understanding of fracture growth behavior in the lease. They were provided with all relevant information to create a generic 3D fracture simulation model which was history matched using mini frac results from 6-21 and 6-23 performed in the 1990s.

The A zone is deepest, and G zone is the shallowest. The A and B zones were of concern because only water is produced from them in this area of the reservoir. The conclusions were that the downward fracture growth would only occur if the fracture initiates below the E zone via perforations in the E (or below) or if a cement channel allows communication below the E zone. The E zone, with proper cement, will act as a barrier to fracture growth initiated elsewhere both in upward and in downward directions. More detail of Pinnacle's work is included in Appendix F.

TECHNOLOGY TRANSFER

As part of the original agreement with the Department Of Energy, it was requested to transfer as much of the experience and information to the general public, so that analogous leases to South Cowden could learn from the techniques and technology applied at South Cowden. Detail of papers and presentations made throughout the project start up and implementation are included in Appendix H.

CONCLUSION

Use of horizontal laterals in a small CO_2 flood for both injectors and producers has been proven to be a technically feasible concept. The economic justification for use of horizontal laterals for CO_2 flooding has not yet been proven. Longer-term oil production response, water-oil ratio, and gas-oil ratio data will be required to make a definitive statement on the economic success or failure. Based on current data, projects of similar net pay, permeability, injection rates and capital development costs are not likely to be economically feasible with crude oil price of $20 to $22 per barrel.

The original tertiary oil recovery base case forecasted was 10.4% of the 86.5 MMBO original oil-in-place within the project area, or 9.0 MMBO. Cumulative tertiary recovery through June 2002 is 600,000 bbls. Ultimate tertiary recovery is estimated to be 3.7 MMBO, or 4.3% of original oil-in-place within the project area. The remaining reserves are based on an oil decline rate of 6% per year exponential decline. No production response from South Cowden Unit injection has been observed on the Emmons Unit, which is due North of the South Cowden Unit.

The original forecasted oil production rates have not been realized primarily due to failure to maintain the CO_2 injection rate and keep the injected CO_2 in the target zones. A second problem has been lower than expected production rates for oil, water, and gas. The re-development plan carried out in 2000 and 2001 addressed these problems, and oil production increased to over 700 BOPD in June 2001. Production has been roughly 620 BOPD and 2,200 MCFD since June 2001. Production is still far less than the original prediction. The base case forecast in the project proposal had a peak unit production of 1,750 BOPD in 2003, declining to 1,500 BOPD by 2010, and 1,000 BOPD by 2018. Redevelopment was only partially successful in increasing reservoir production rates, so that lower average reservoir pressure could be maintained. Gas production has been stable in the range of 2,100 to 2,300 MCFD since early 2001. Graphs and tables with details of oil, gas, water production, and injection for the Unit and sub-areas within the unit are presented in Appendix D – Monitoring Flood Performance.

Low injection rate for CO_2 is a major concern. The original plan called for a 40% cumulative hydrocarbon pore volume (HCPV) slug of CO_2. Cumulative CO_2 injected through June 2002 is 13.7 BCF, equal to 6.6 % HCPV. At the current injection rate of 5.7 MMCFD, the 40% CO_2 slug would be reached in the year 2035, assuming continuous CO_2 injection without water slugs. For calculation purposes, a formation volume factor of 2.1 MCF / reservoir barrel was used.

With a few exceptions, injection of CO_2 has been continuous into each well since the start of the project. Water injection slugs have so far only been used to minimize risk during well interventions at the injector, or on nearby wells. No significant loss of injection has been observed following changes from CO_2 to water, or from water to CO_2. When produced gas capacity exceeds the recycle compression capability, the use of water slugs to reduce gas production will likely be used. As planned, all produced gas was re-injected, with no NGL recovery from the gas stream.

The predicted long-term increase in horizontal injector CO_2 rates versus historical vertical injector rates have not been achieved. As shown in the table of monthly CO_2 injection by well (see Appendix D "Monitoring Flood Performance"), injection rate versus time has declined on most of the CO_2 injection wells. This is attributed to increased reservoir pressure surrounding the injectors. The reservoir pressure is so high surrounding wells 2-27W and 6-27W that no CO_2 injection is possible within the surface pressure limit. It should be noted that a substantial portion of vertical well CO_2 injection was measured to be going out of the pay zone.

The forecasted gross CO_2 utilization of 8.5 MCF/BO has not yet been achieved. Cumulative gross CO_2 utilization through June 2002 is 21 MCF/BO. Instantaneous utilization as of June 2002 is 10 MCF/BO. Gross utilization is defined as total CO_2 injection in MCF / Tertiary Oil recovery, in stock tank barrels. Net utilization is defined as purchased CO_2 injection in MCF / Tertiary Oil recovery.

CO_2 injection projects should include alternate plans for produced water disposal in case primary plans do not result in maintaining res ervoir pressure within the target range.

Injection profile logging is essential to measurement of vertical conformance. Frequent logs early in the flood are needed to detect out-of-zone waste of CO_2 and water injection. Periodic profile logging throughout the flood life is recommended.

No cost effective injection profile logging techniques have been found to date for horizontal laterals. Logging tools with electronic downhole memory have been run on coiled tubing, but are very expensive both due to log charges and coiled tubing unit charges. Since surface readout of data is not possible, conventional injection profile techniques are not applicable, and specific problem depths are not identified until after logging is completed.

A defined well production rate-testing program is essential to proper allocation of produced oil, gas, and water. Monthly data quality checking methods should be followed to assure accurate measurement and record keeping for both produced volumes and of water and CO_2 injected.

As of this report date, ConocoPhillips intends to continue CO_2 and water injection into the current injection wells, and maintain production operations so long as revenues justify the costs of operations. There are no current plans for any additional capital expenditures on the South Cowden Unit.

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LIST OF ACRONYMS AND ABBREVIATIONS

%		Percent
3-D		Three dimensional
AAPG		American Association of Petroleum Geologists
AFE		Authority for Expenditure
bbl		Barrel
BFPD		Barrels Fluid Per Day
BHA		Bottom Hole Assembly
BHP		Bottom Hole Pressure
BOPD		Barrels Oil Per Day
BPD		Barrels Per Day
BSCF		Billion Standard Cubic Feet
BWPD		Barrels Water Per Day
cc		Cubic Centimeter
CO_2		Carbon Dioxide
CPET		Cathodic Protection Evaluation Tool
CT		Coil Tubing
DOE		Department of Energy
EOR		Enhanced Oil Recovery
F		Fahrenheit
GOR		Gas Oil Ratio
H_2S		Hydrogen Sulfide
HCL		Hydrochloric Acid
HCPV		Hydrocarbon Pore Volume
Hp		Horsepower
Hrs		Hours
ID		Internal Diameter
ISDP		Instantaneous Shutdown Pressure
Kh		Permeability Feet
K_v		Vertical Permeability
mD		Millidarcy
Mins		Minutes
MMP		Minimum Miscibility Pressure
MMSCFD		Million Standard Cubic Feet Per Day
MMSTB		Million Stock Tank Barrels
MSCFD		Thousand Standard Cubic Feet Per Day
MSTB		Thousand Stock Tank Barrels
MWD		Measurement While Drilling
º		Degrees
OOIP		Original Oil in Place
OWC		Oil Water Contact
P&Aʻd		Plug and Abandoned

PH		Precision Hydril Thread
POI		Production Operators, Inc.
POOH		Pull Out of Hole
PPF		Pounds Per Foot
PSIA		Pounds Per Square Inch Absolute
PSIF		Pounds Per Square Inch Per Foot
PSIG		Pounds Per Square Inch Gauged
PVT		Pressure Volume Temperature
RC		Reservoir Characterization
RF		Resistance Factors
RKB		Rotary Kelly Bushing
SAG		Surfactant Alternating With Gas
SCADA		Supervisory Control and Data Acquisition
SCF/BO		Standard Cubic Feet Per Barrel of Oil
SCU		South Cowden Unit
SEPM		Society of Economic Paleontologists and Mineralogists
SF		Sulphur Hexafloride
SPE		Society of Petroleum Engineers
SSC		Shallow Shelf Carbonate
STBO		Stock Tank Barrels f Oil
TA		Temporarily Abandoned
TMD		Total Measured Depth
TRRC		Texas Railroad Commission
TVD		True Vertical Depth
WAG		Water Alternating Gas
WL		Wireline
WOR		Water Oil Ratio
XF		Half Length

APPENDIX A

Reservoir Characterization and Reservoir Model

Appendix A

INDEX

Summary

Drill, Core, Complete, Test, and Evaluate Well RC-3 (SCU 6-24)
Complete Petrologic Description of Core from Well RC-3
Updating Geological/Reservoir Model
Initial Simulation Development Sensitivities with Revised Model
Updating Performance Predictions

Summary

Since Budget Phase I completion, additional well data and revised porosity/permeability relationships were incorporated into a new geological/reservoir model. The new model was completed in 1996. The work involved is discussed below. The original authority for expenditure (AFE) model, used for Budget Phase I, was therefore superseded in late 1996 with a new model to revise forecast predictions for Budget Phase II.

Visual inspection of the porosity/permeability distribution in the geologic model indicated the E zone interval (the primary target for carbon dioxide (CO_2) flooding) could be separated into four units, compared to three in the original AFE model. These flow units were distinguished by small variations in porosity/permeability that were somewhat correlatable between wells. These four layers in the E, in addition to the F layer, upper D layer, and C layer, comprised the seven flow units in the reservoir simulation model.

Maps of structure, thickness, average porosity, and geometric average permeability were extracted from the geologic model to the seven simulation layers.

The South Cowden full field geological and the subsequent simulation model were therefore updated for:

(a) Inclusion of data from five additional wells drilled in the project area, and

(b) Improvements in delineating the porosity and permeability distribution in the project area. This was obtained by integrating production performance data into the three dimensional (3-D) geological modeling.

The resulting simulation model grid was 54 x 54 x 7 (20,412 active cells). The revised field performance history match obtained using the updated geologic model resulted in significant improvements in individual well performance matches.

Full-field simulation runs were completed to evaluate various developments of horizontal and vertical CO_2 water alternating gas (WAG) injection wells. The most effective configuration was determined to be one in which horizontal CO_2 WAG injectors were positioned in down-structure locations (oriented approximately parallel to structural strike) in combination with vertical WAG injection wells in structurally higher locations. The simulation runs indicated vertical permeability restrictions in the lower reservoir would limit vertical distribution of

injected CO_2 into lower intervals if horizontal injection wells were used. Application of horizontal CO_2 injection wells was therefore, effective in down-structure locations where the majority of reservoir pore volume lies below the original oil-water contact.

The initial revised model, discussed above, was completed in 1996. In subsequent years, during Budget Phase II, model updates were made annually to incorporate the exact project development and operating schedule. The model was adjusted to reflect the details of the actual locations, completions, and timing of newly drilled, reactivated, and recompleted wells in the CO_2 flood project area.

Of significant note was the productive capacity of several reactivated production wells. These were either new wells drilled immediately offsetting abandoned wells with poor casing integrity, or wells re-entered in the mid 1990s that were previously temporarily abandoned. The new or re-entered wells were designed to increase offtake for the lease for the CO_2 project. Rates were initially significantly less than premised in the original forecasts (based on the productivity prior to shut-in or offset wells).

Overall "in zone" injectivity throughout the lease averaged 55%. The majority of the "in zone" CO_2 injection being achieved in well 6C25H horizontal well, with little or no in-zone injection in vertical CO_2 injection wells.

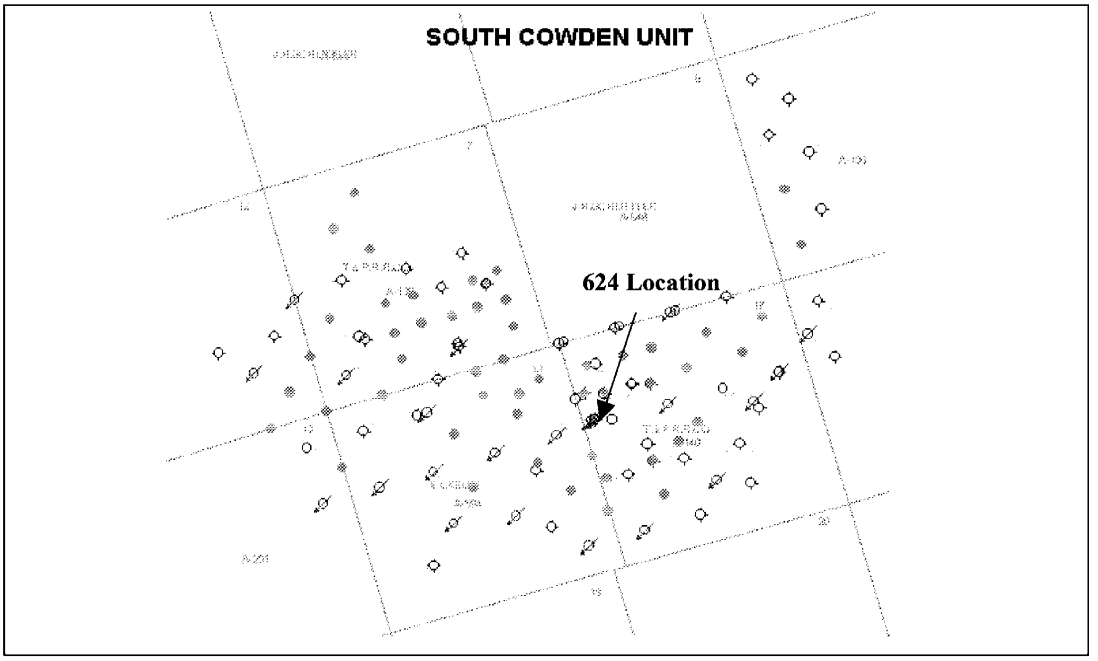
It was apparent the overall initial flood response had not been encouraging. Several wells were not injecting or producing as expected, resulting in a poor overall CO_2 response.

The history matched model, incorporating poorer producing well productivity, poor in zone injection and overall poor CO_2 processing and throughput in the Upper San Andres, suggested that unless a significant redevelopment was undertaken to improve the flood the economics and tertiary reserves predicted would not be achieved.

Drill, Core, Complete, Test, and Evaluate Well RC-3 (SCU 6-24)

The third reservoir characterization well (RC-3) for the project was given the well number SCU 6-24, which was drilled in November and December 1995. The location of the well is shown on the map below. Prior to drilling, this location was believed to be in the center of the main CO_2 flooding area, where excellent quality rock would be intercepted.

Appendix A



Core was taken from the depth interval 4586'-4766', recovering 179.5 feet of core. Routine whole core analysis measurement of porosity, permeability, and fluid saturations were completed. The core was slabbed and sent to the Phillips core facility in Bartlesville where a petrographic study was performed, including macroscopic core description and thin sections.

Well logs indicated greatly reduced porosity in the Upper E and F zones, compared to offset wells. Initial examination of the core indicated anhydrite cementation may be responsible for the porosity reduction, and permeability was lower than anticipated.

Complete Petrologic Description of Core from Well RC-3

Burrow-mottled dolopackstones composing the South Cowden Unit (SCU) reservoir interval are composed of gray, relatively low-porosity and low-permeability dolowackestones/dolopackstones and tan, oil-stained, more porous and permeable dolopackstones/dolograinstones. Tan dolomite areas are burrows. Interburrow areas are gray lower porosity dolomite. The relative amounts of gray and tan dolomites composing the SCU reservoir interval markedly affect the reservoir porosity and permeability. A clear mylar sheet with a one-inch-square grid pattern was used to determine the relative amounts of gray and tan dolomites composing the reservoir interval in the SCU 6-24 core. These amounts, determined for each one-foot interval of the Grayburg reservoir, will be compared with gray/tan percentages similarly determined for the SCU 8-19, 7-10, 6-23, and 8-11 cores.

Reservoir porosity is also a function of anhydrite content. Thin section study of burrow mottled dolopackstones from the SCU 8-19, 7-10, 6-23, and 8-11 and the Moss Unit 16-14 shows that as anhydrite content increases reservoir porosity decreases. Thin section study of reservoir dolomites from the SCU 6-24 confirms these findings. Average anhydrite content of tan dolomites, determined from thin sections; and average porosities, determined from core analysis, are given in the following:

Appendix A

AVERAGE WELL	AVERAGE POROSITY	ANHYDRITE
SCU 8-19	24%	1%
SCU 6-23	21%	1%
SCU 7-10	21%	5%
SCU 8-11	14.5%	11.5%
Moss 16-14	6%	15.5%

Anhydrite content in the lower part of the reservoir interval in the SCU 6-24 well (Zone E below 4675', log depth) averages less than 1% anhydrite. Porosity estimated from thin sections for this interval is approximately 12%. Zones E and F above 4675' average 19% anhydrite and 4.5% porosity as determined from thin sections (porosities estimated from thin section are typically lower than those determined by core analysis).

Tan dolomite areas have varying permeabilities related to pore size. Tan dolomites with similar porosities may have markedly different permeabilities. The average porosity of tan dolomites from SCU 6-23 and 7-10 is 21%, but the average permeabilities are 90 md and 10 md, respectively. Tan dolomites from SCU 7-10 have markedly smaller pores and finer dolomite crystal size than tan dolomites from SCU 6-23. Tan dolomite samples from SCU 6-24 vary markedly in crystal size and consequent pore size, resembling samples from both SCU 7-10 and 6-23.

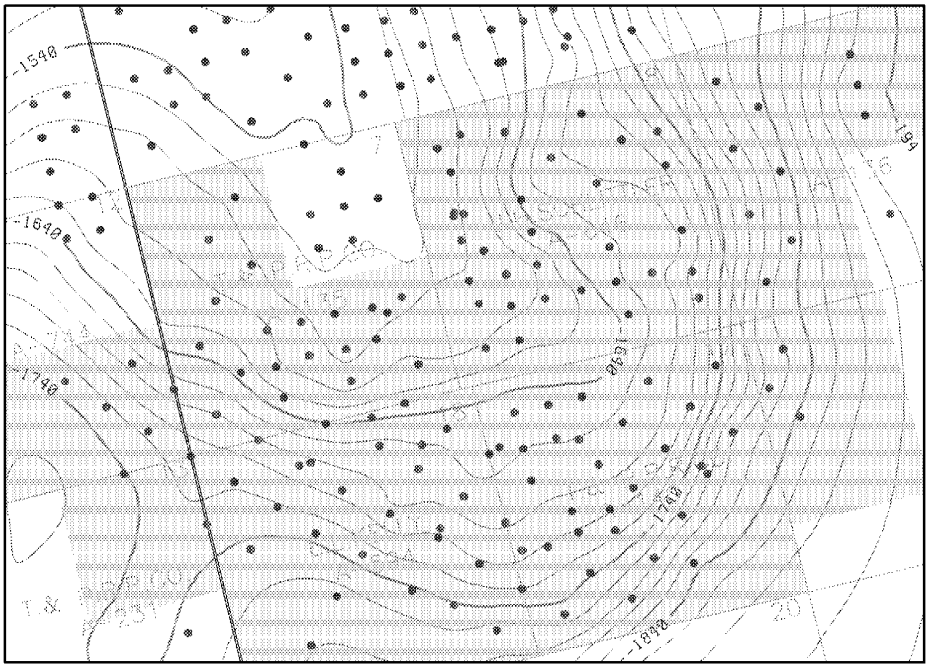
Updating Geological/Reservoir Model

Permeability was computed for each well with digital log data using correlations to core permeabilities and well production rates. This data was imported into STRATAMODEL software, and a three dimensional (3-D) interpolation of the permeability distribution was completed. A three-dimensional porosity distribution had also been completed for the model.

Visual inspection of the porosity/permeability distribution in the geologic model indicated the E zone interval (the primary target for carbon dioxide (CO_2) flooding) could be separated into four units, compared to three in the original AFE model. These flow units were distinguished by small variations in porosity/permeability that were somewhat correlatable between wells. These four layers in the E, in addition to the F layer, upper D layer, and C layer, comprised the seven flow units in the reservoir simulation model.

Maps of structure, thickness, average porosity, and geometric average permeability were extracted from the geologic model to the seven simulation layers. Maps for the F, E, D and C layers are shown below, which illustrate the dissimilarity between porosity and permeability distribution in the field.

Appendix A



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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

F_ELEV

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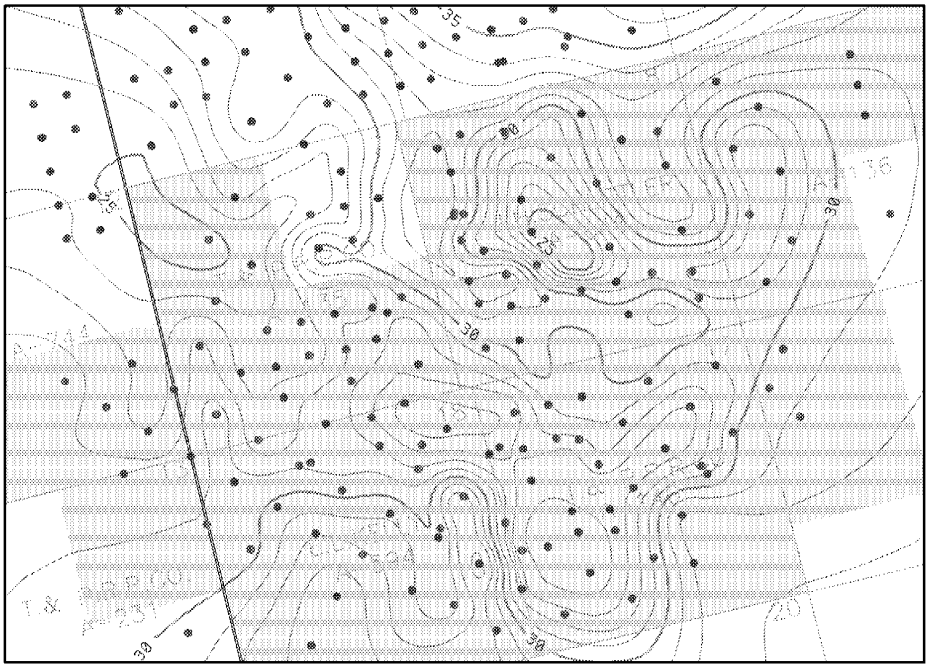

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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

F_THICK

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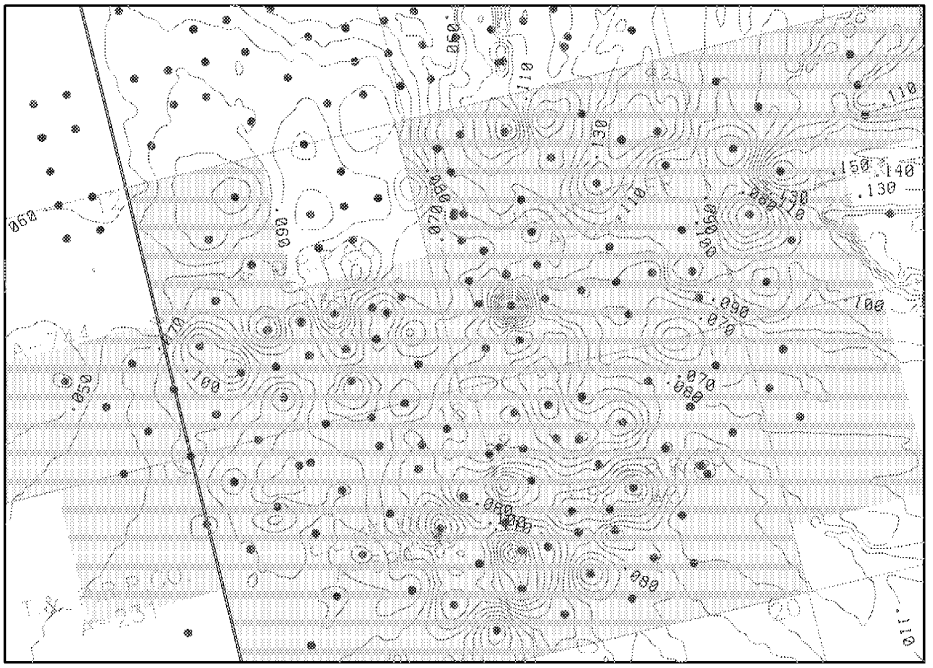

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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

F_PORE

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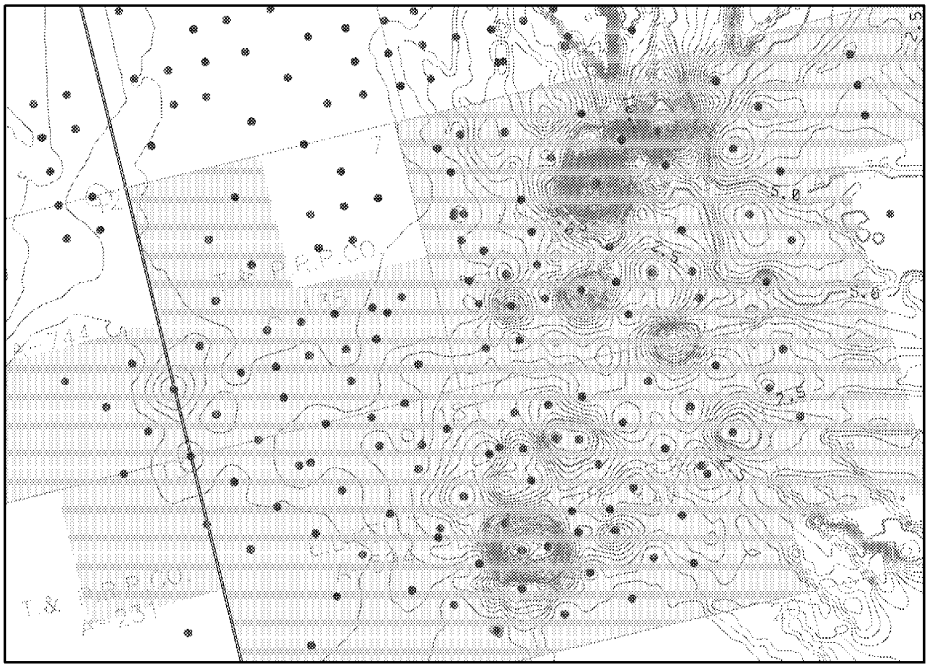

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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

F_PERM

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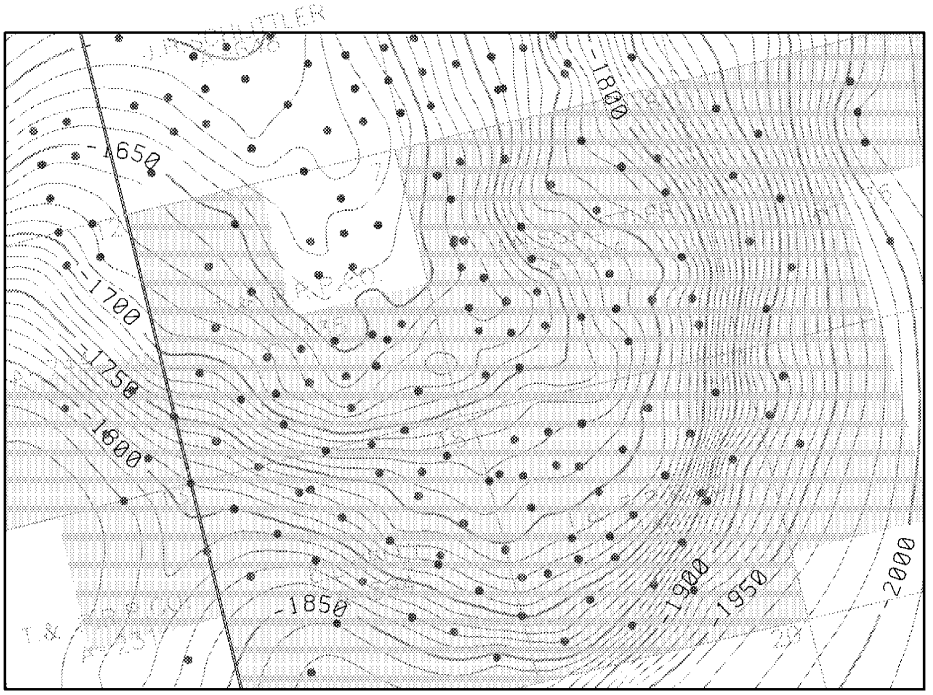

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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

E1_ELEV

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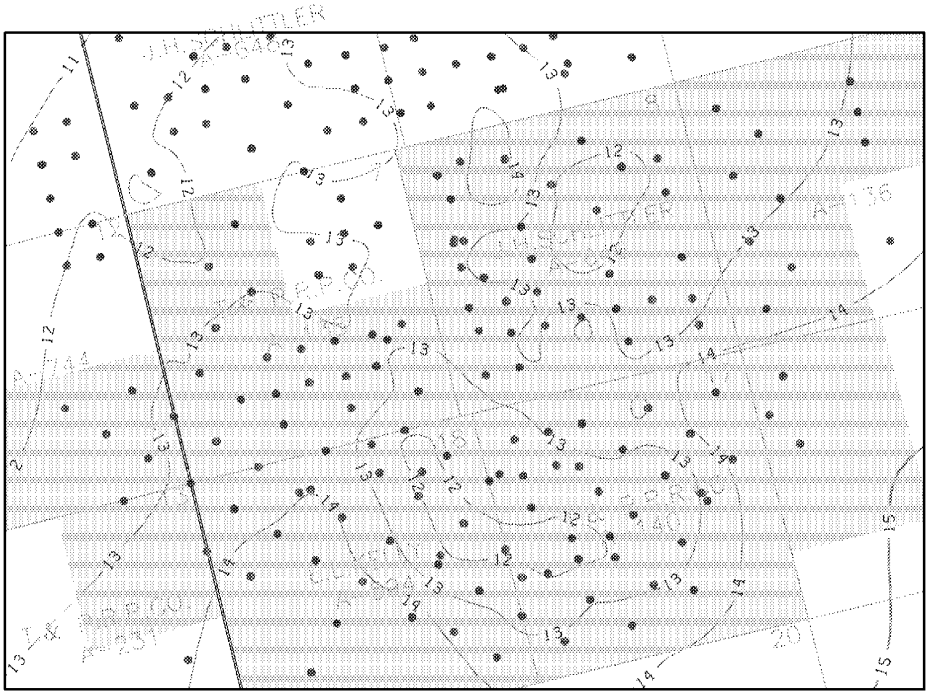

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SOUTH COWDEN UNIT

E1_THICK

MATT GERHARD | 12-FEB-2001

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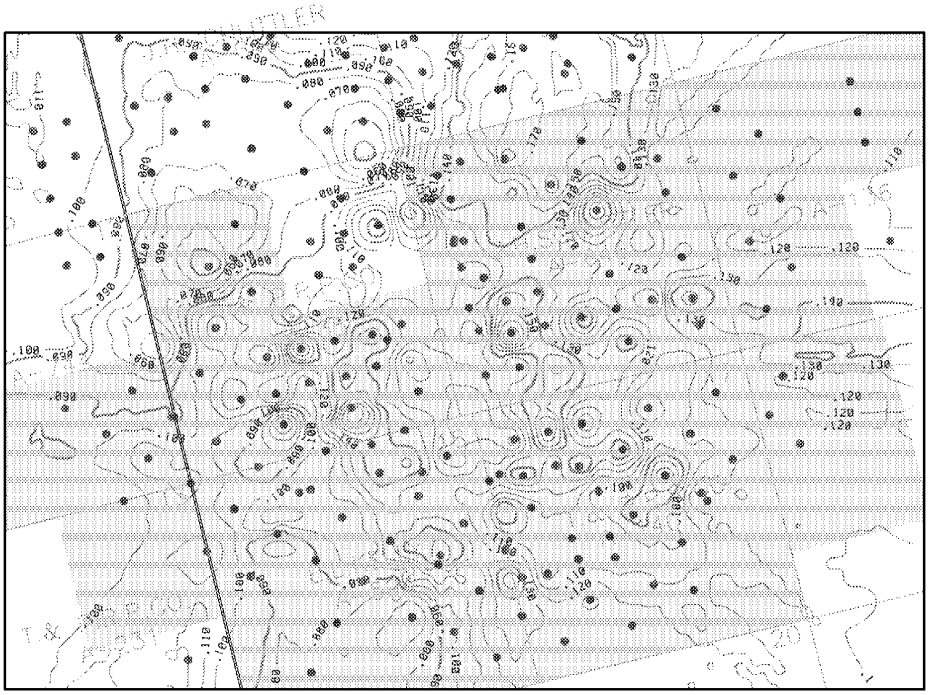

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SOUTH COWDEN UNIT

E1_PORE

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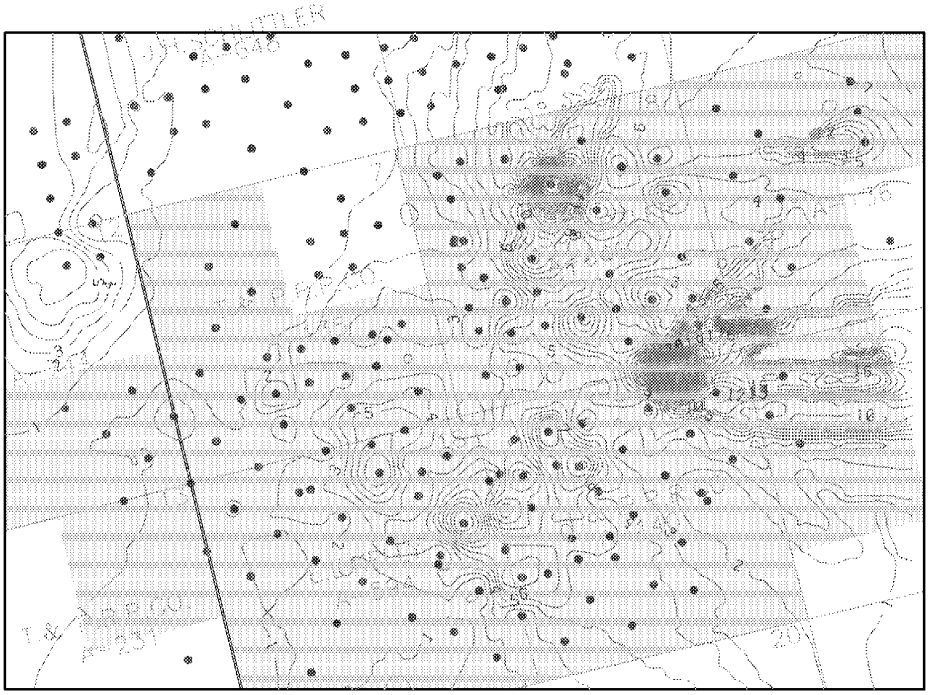

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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

E1_PERM

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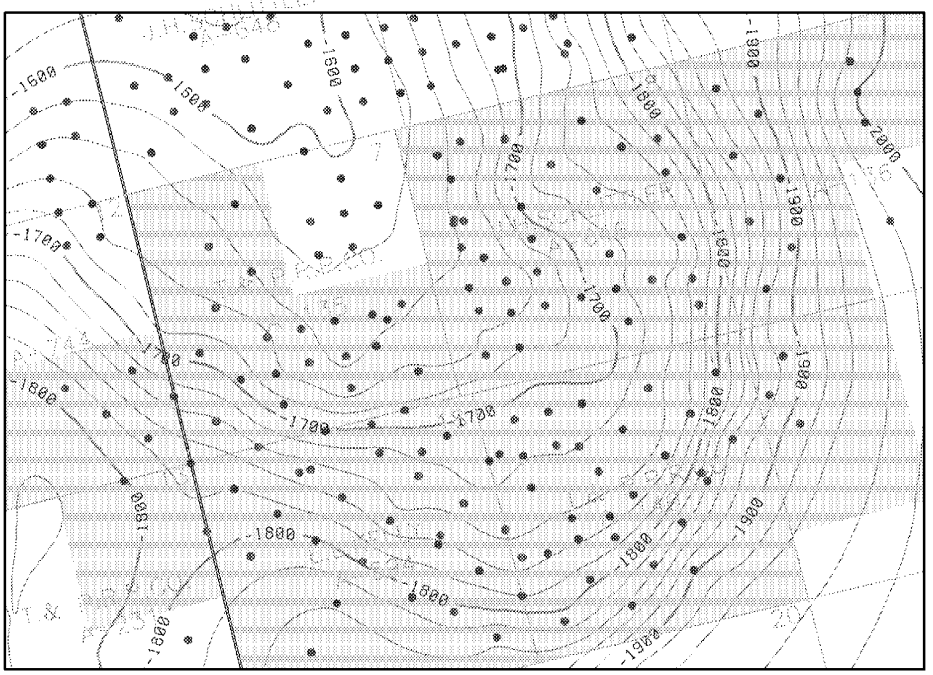

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SOUTH COWDEN UNIT

E2_ELEV

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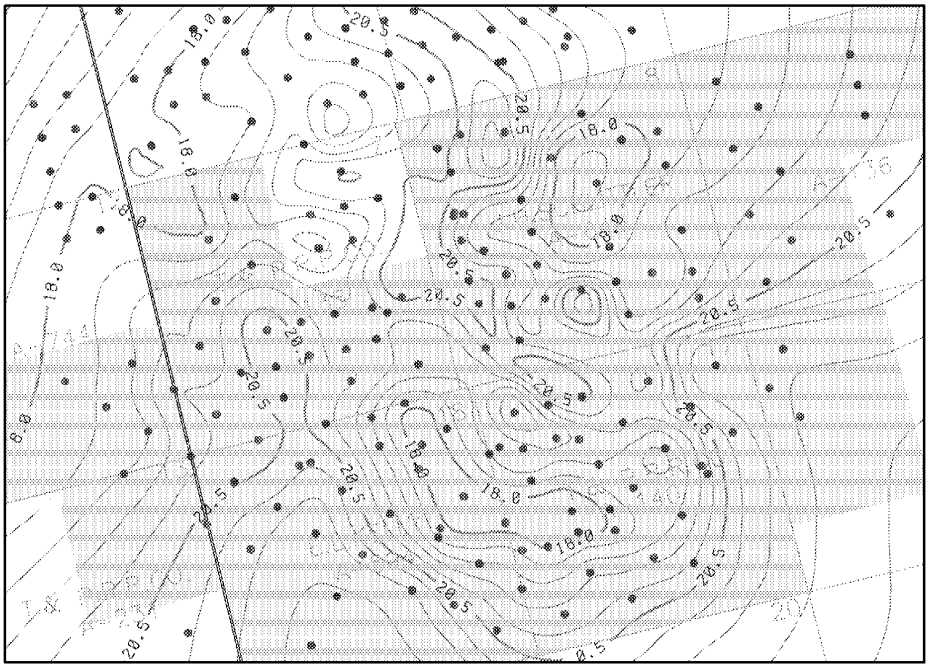

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SOUTH COWDEN UNIT

E2_THICK

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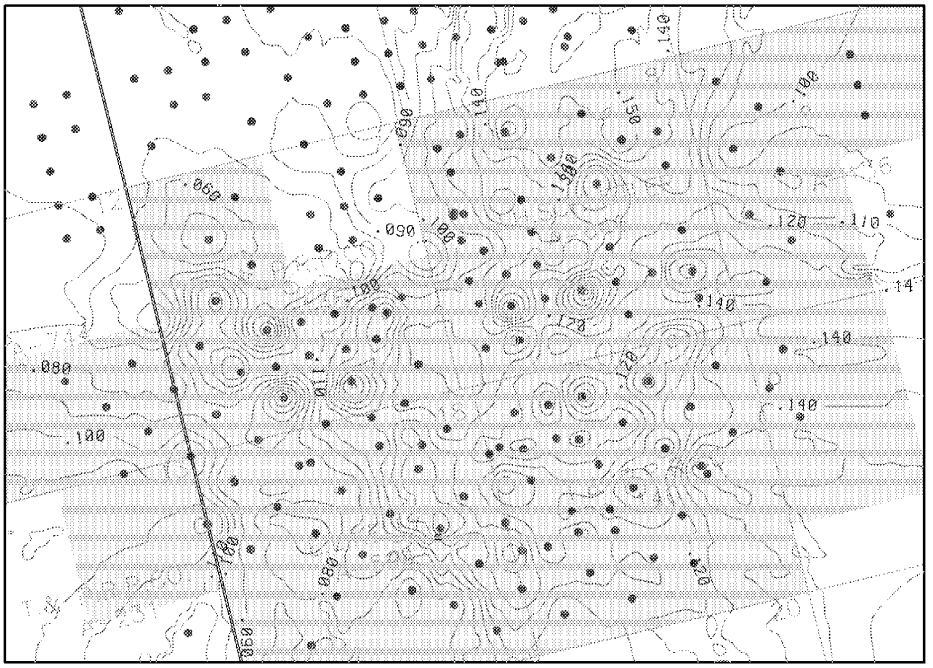

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E2_PORE

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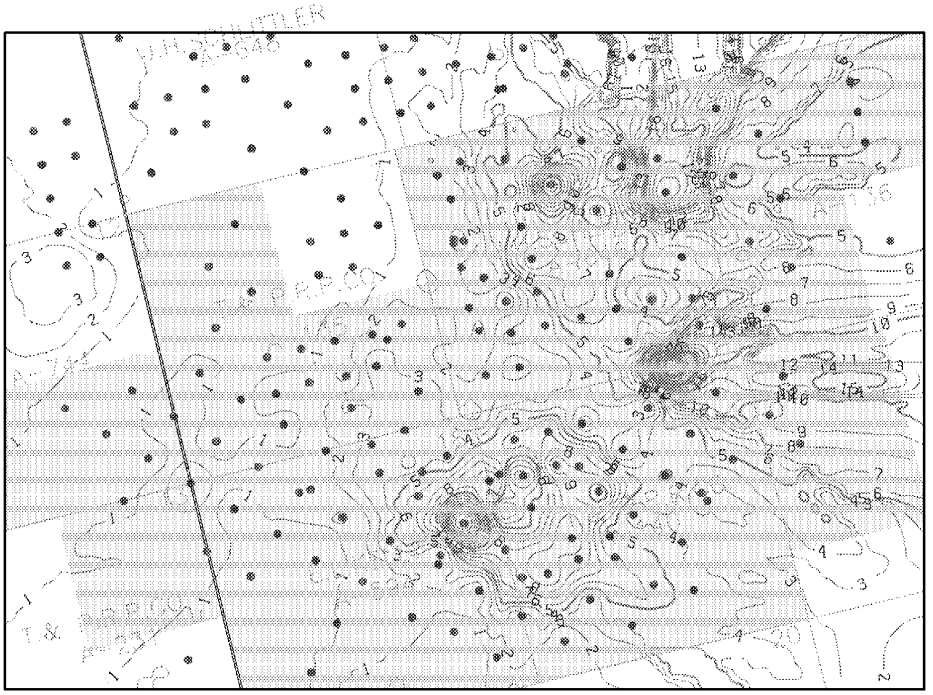

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E2_PERM

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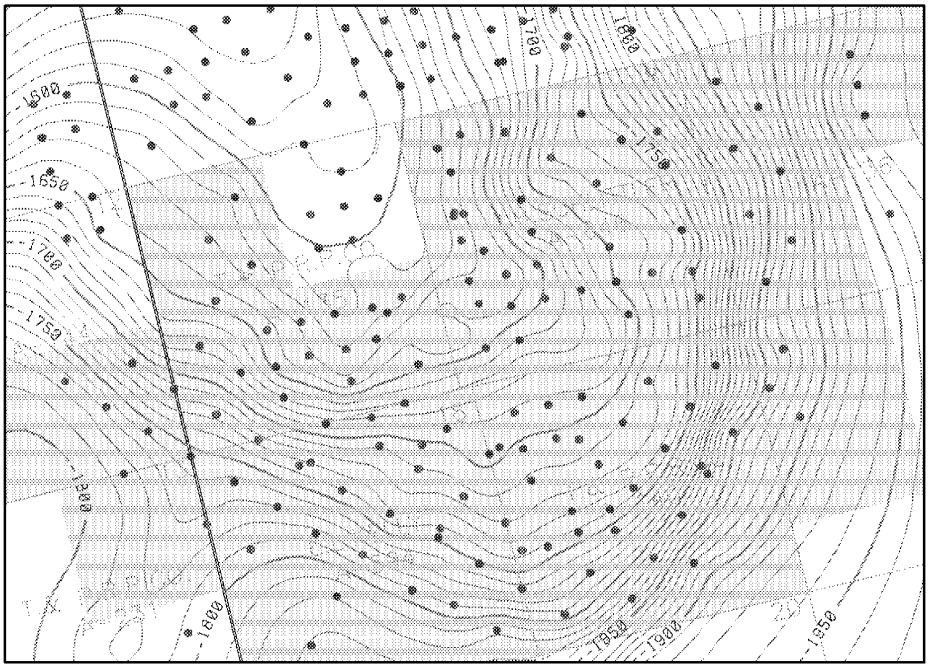

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SOUTH COWDEN UNIT

E3_ELEV

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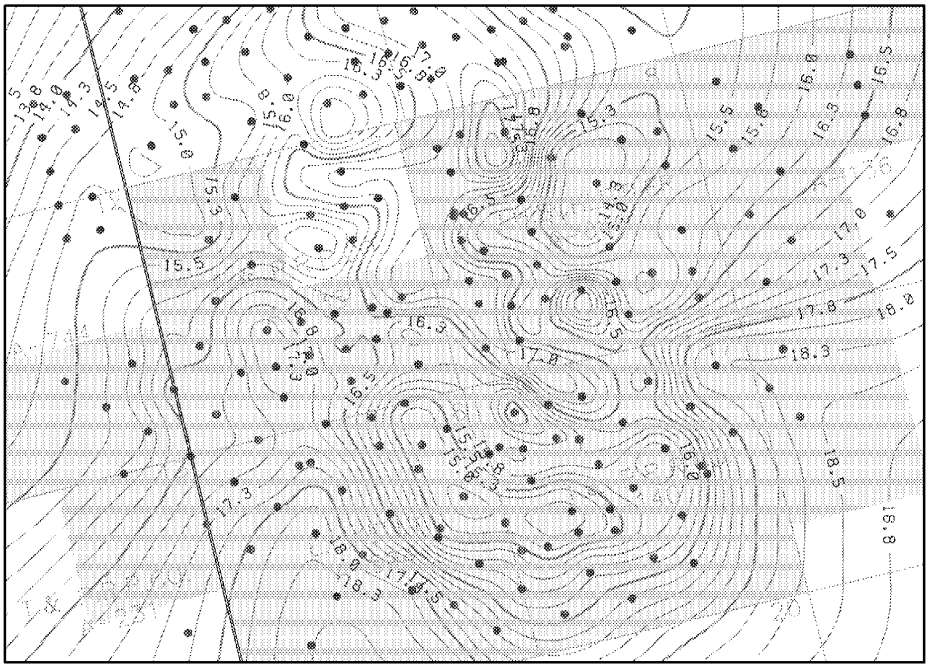

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SOUTH COWDEN UNIT

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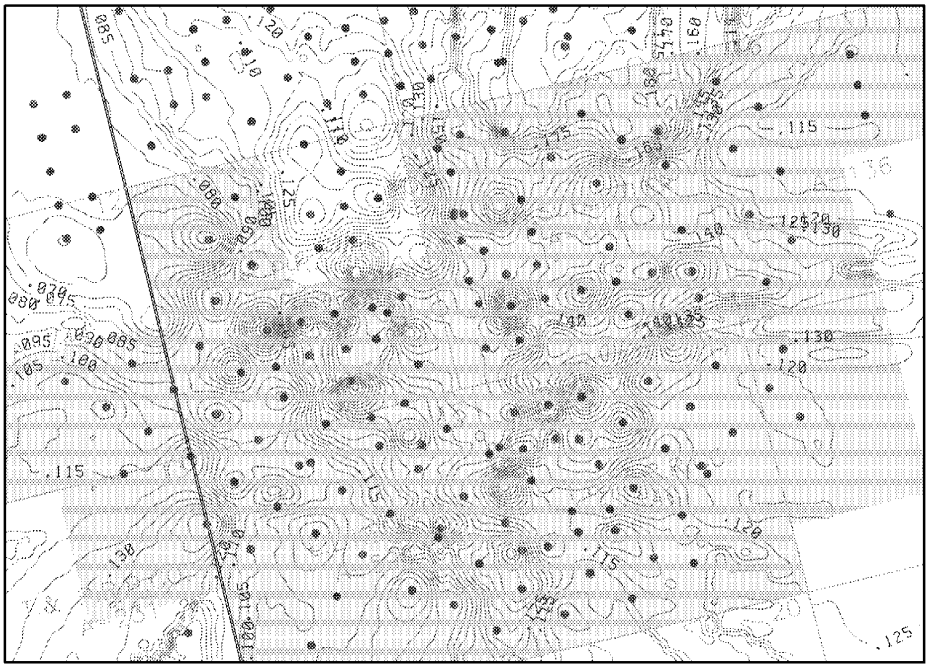

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SOUTH COWDEN UNIT

E3_PORE

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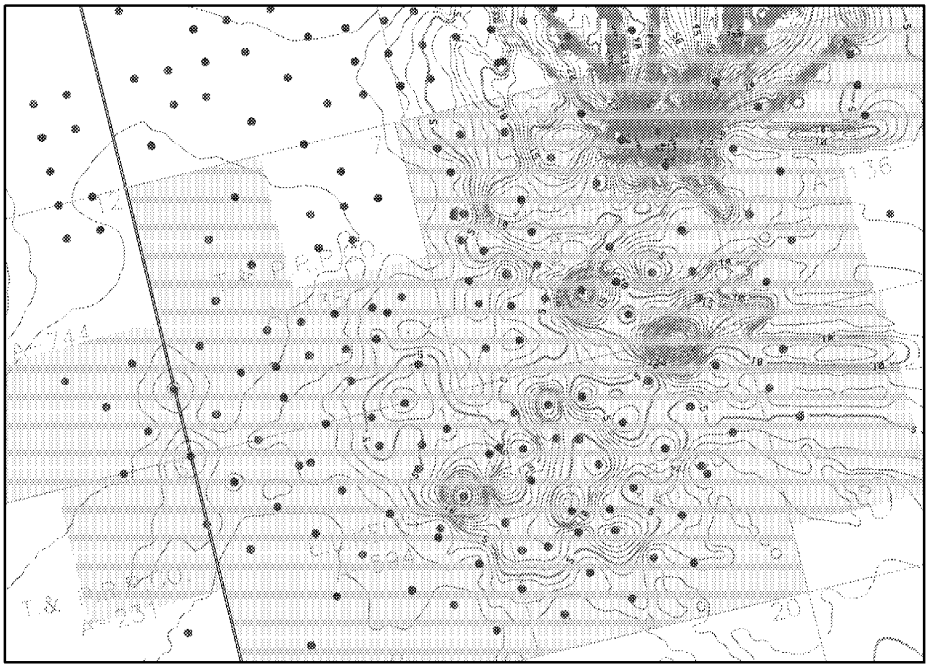

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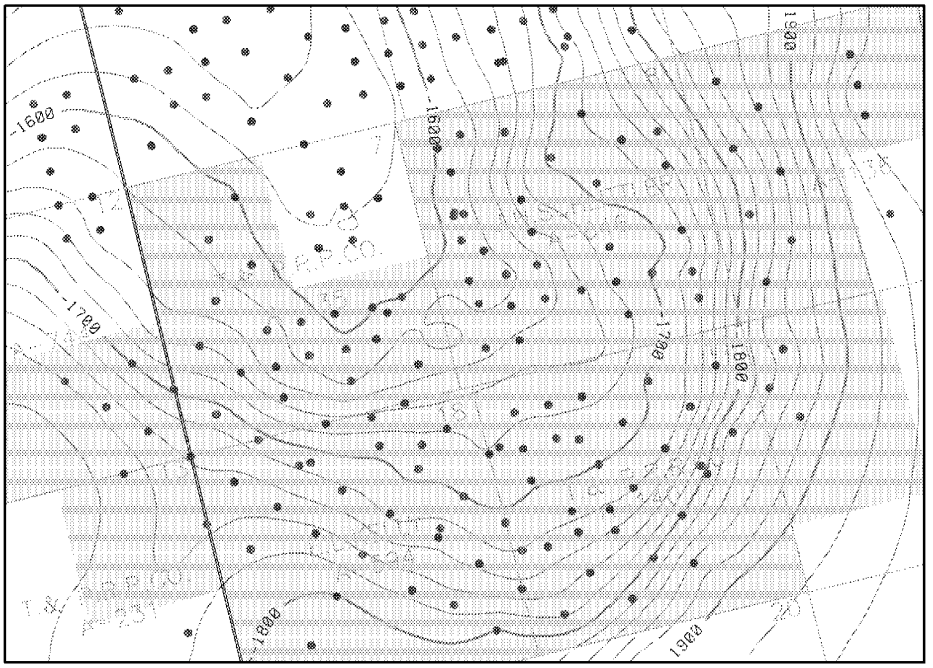

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SOUTH COWDEN UNIT

E4_ELEV

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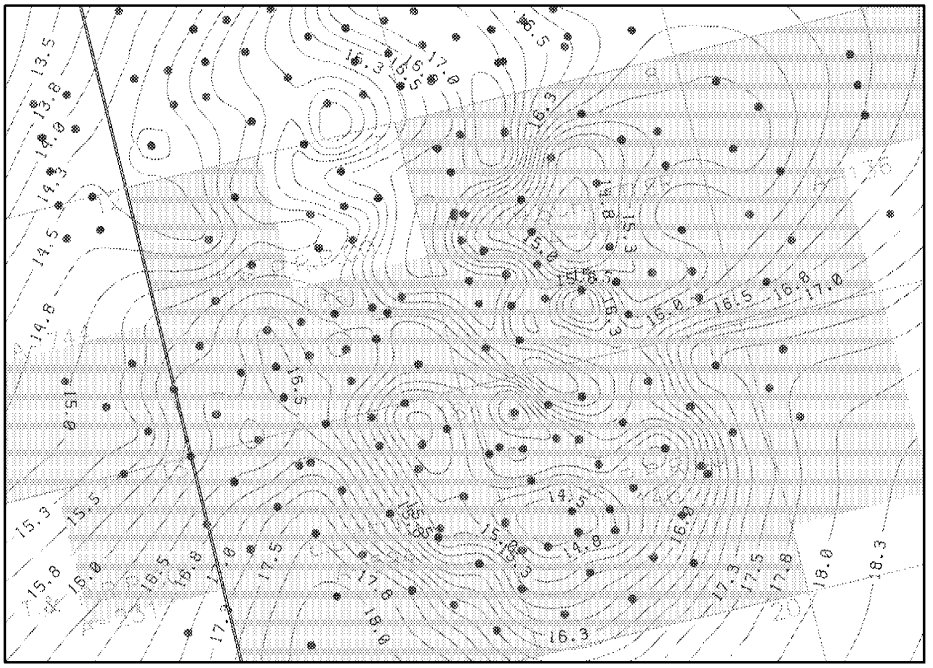

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E4_THICK

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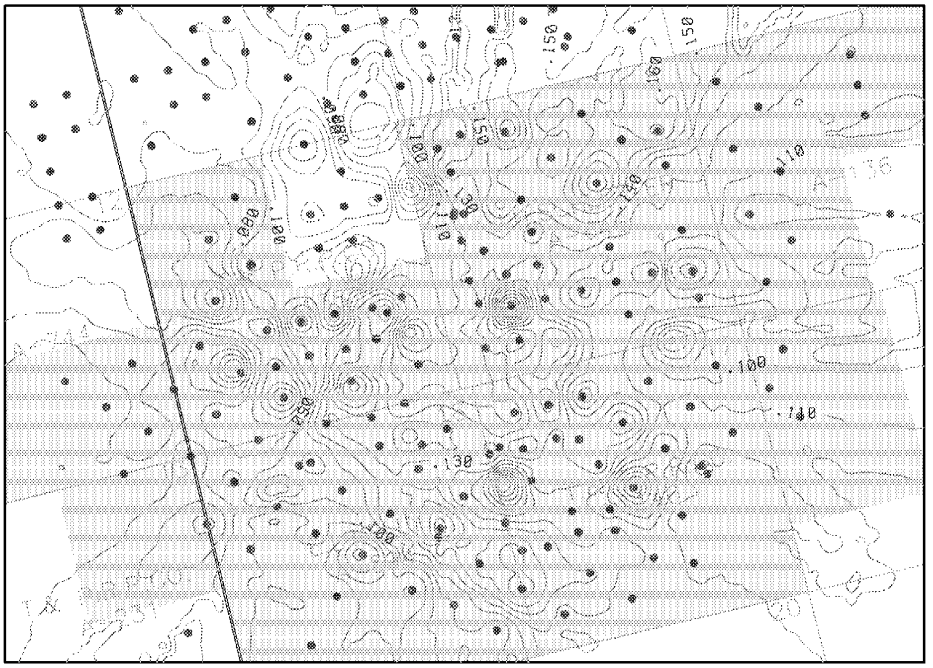

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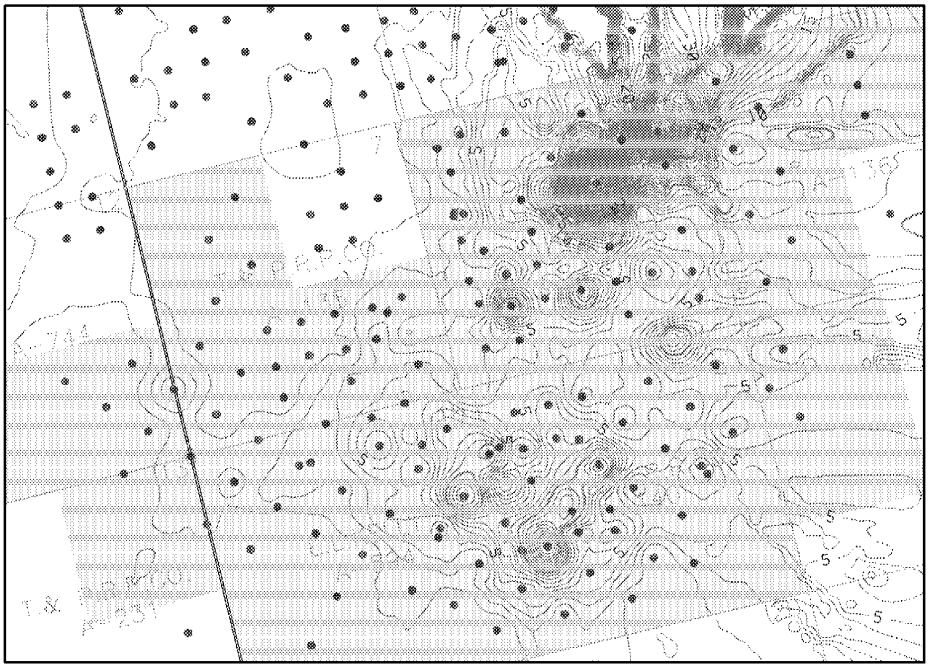

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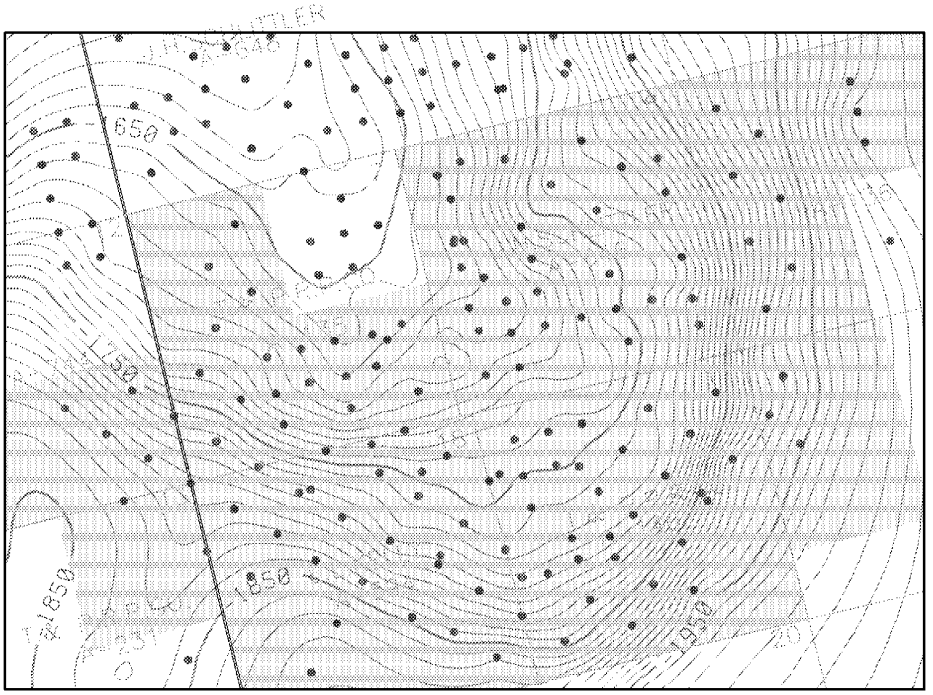

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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

D_ELEV

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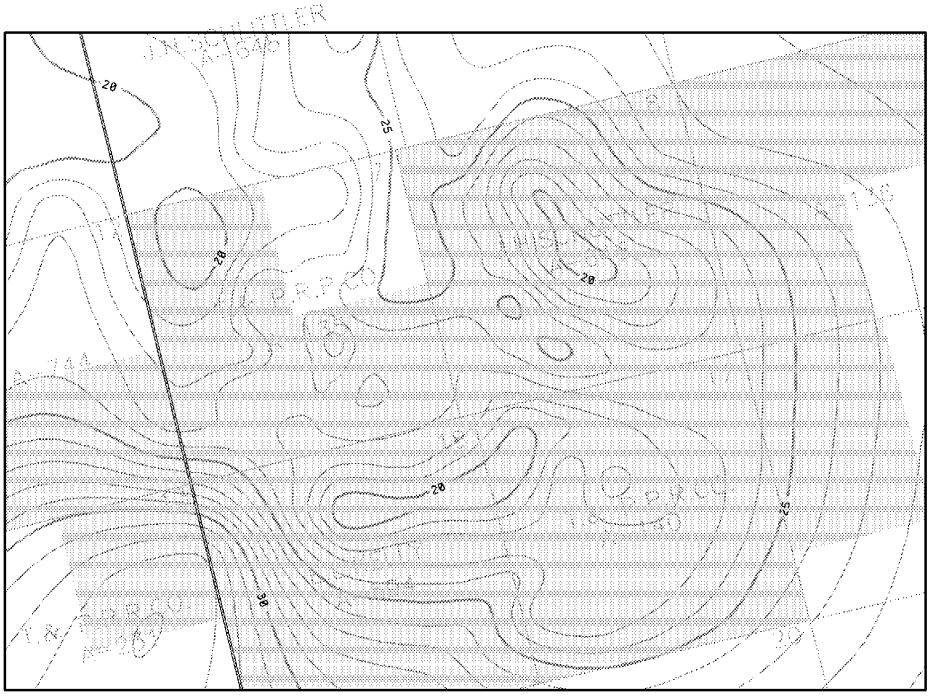

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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

D_THICK

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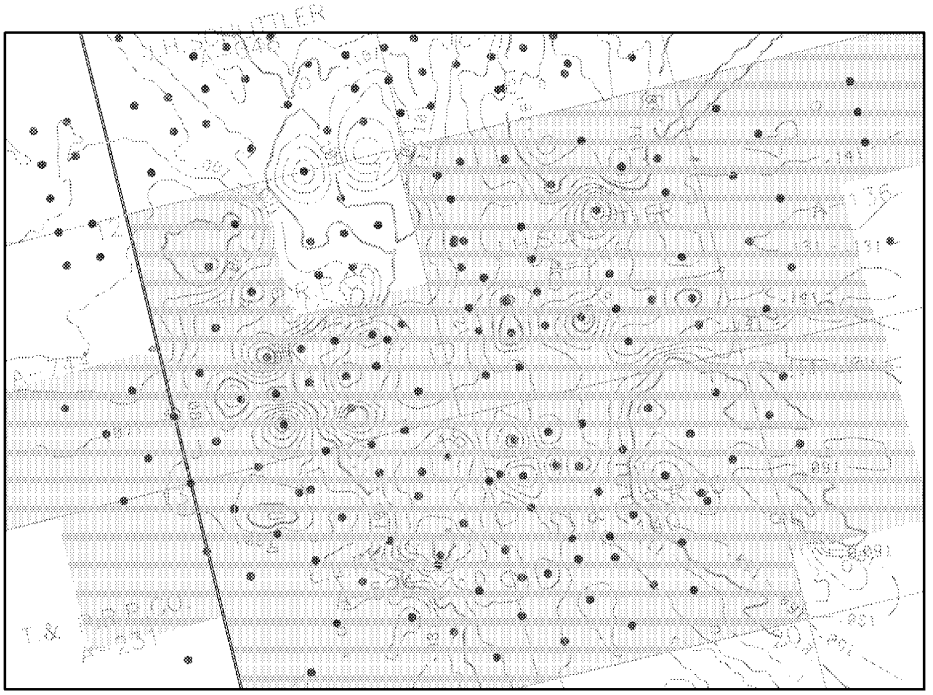

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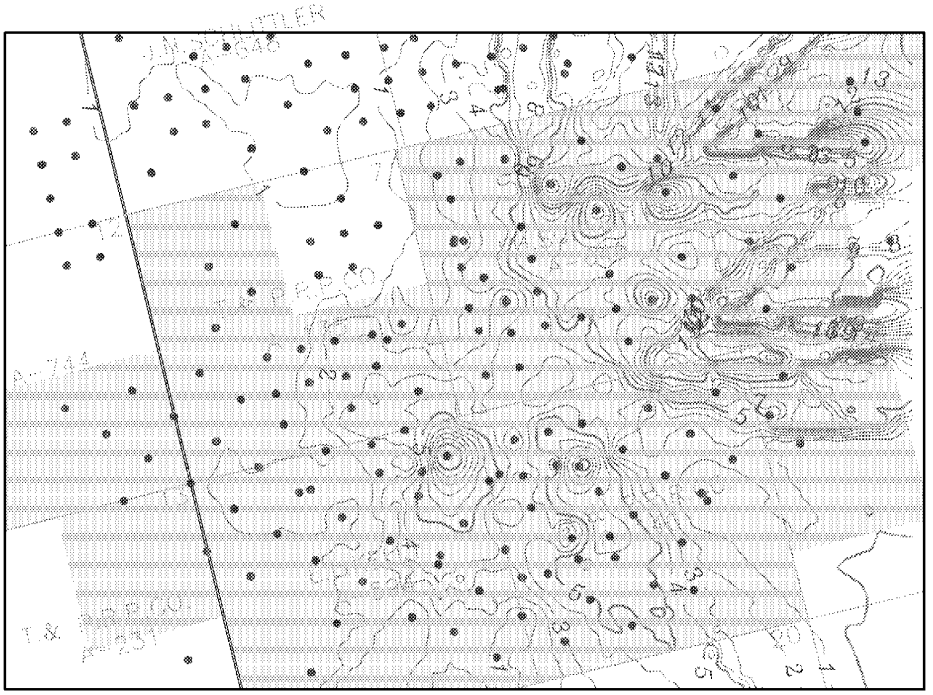
PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

D_PORE

Appendix A



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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

D_PERM

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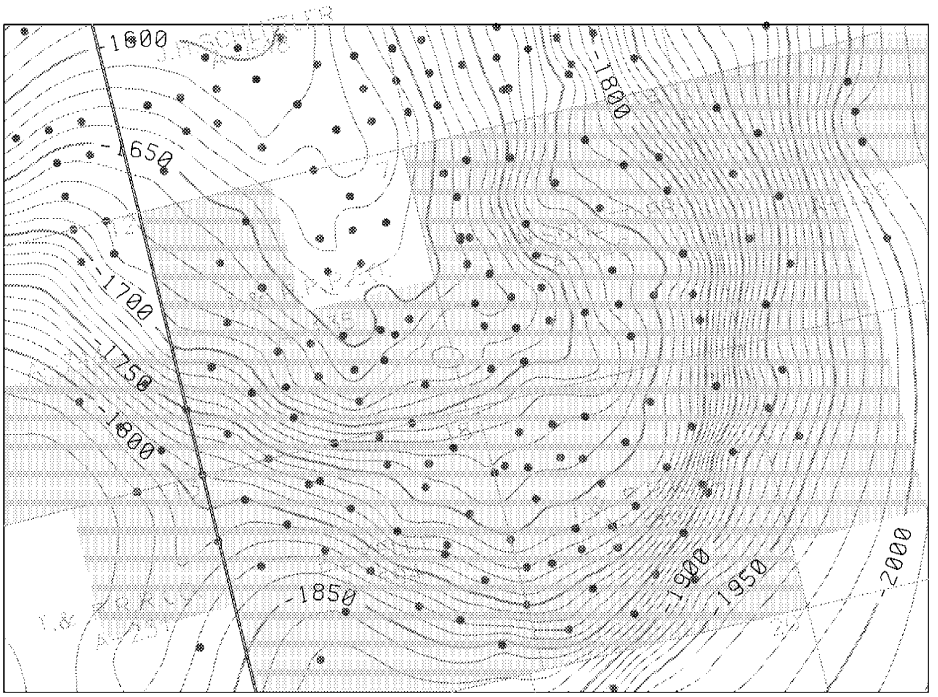

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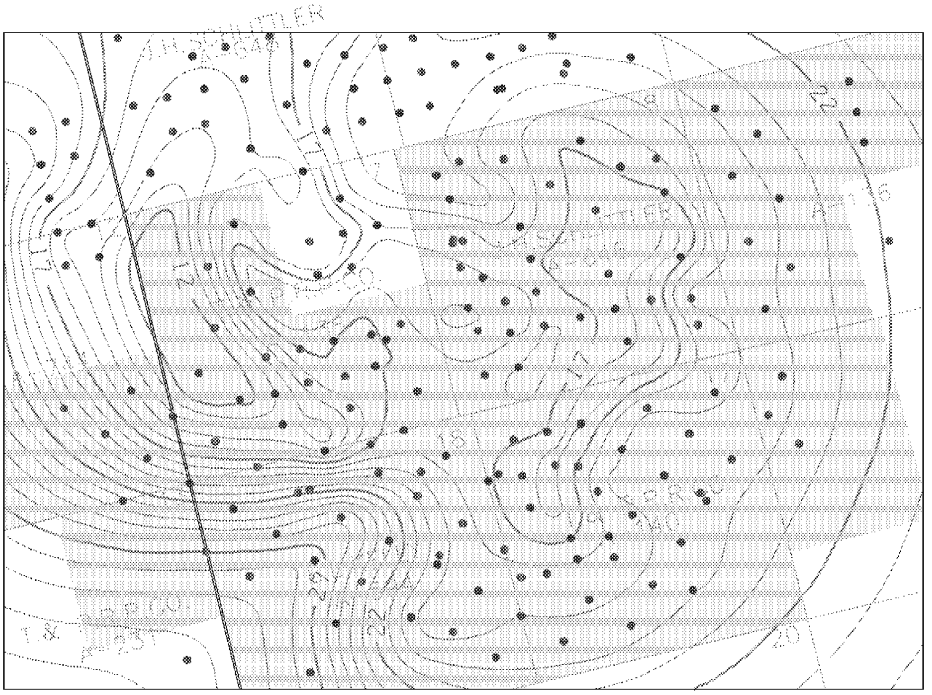
PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

C ELEVATION

Appendix A



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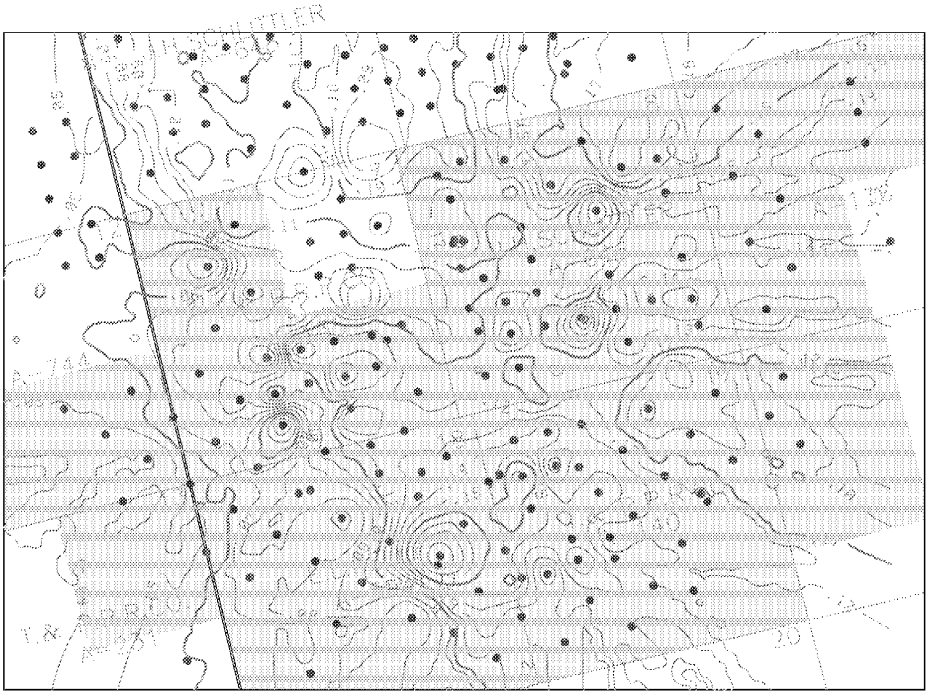
PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

C_THICK

Appendix A



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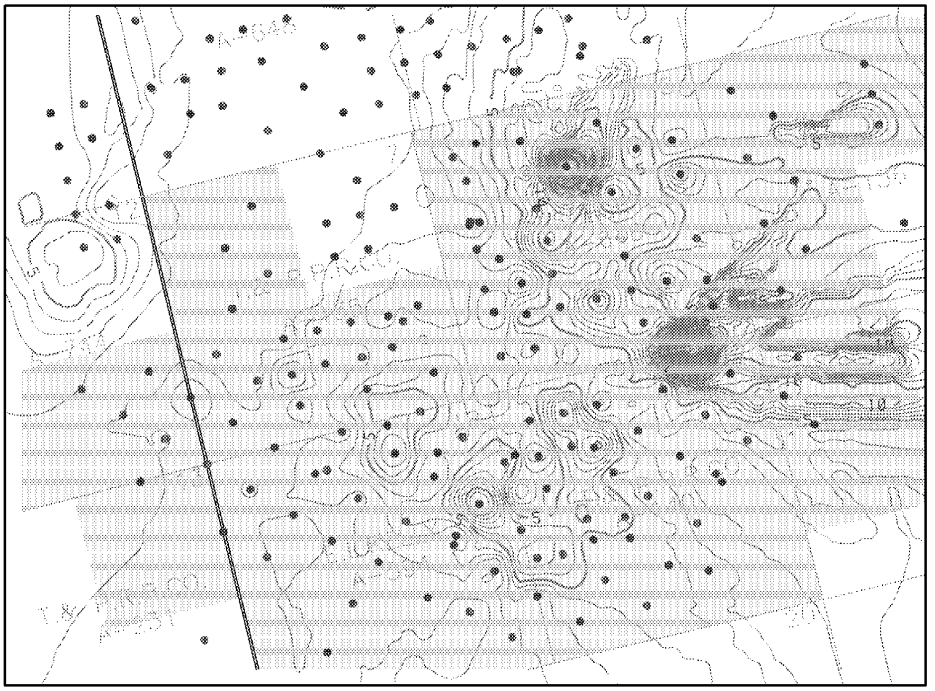
PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

C_PORE

Appendix A



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PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT

C_PERM

MATT GERRARD 13-FEB-2001

The South Cowden full field geological and the subsequent simulation model were therefore updated for:

(a) Inclusion of data from five additional wells drilled in the project area, and

(b) Improvements in delineating the porosity and permeability distribution in the project area. Improvements in delineating permeability distribution in the reservoir were obtained by integrating production performance data into the 3-D geological modeling.

The updated geologic model was divided into four subunits, as discussed above, to better reflect the porosity and permeability structure within Zone E. The resulting simulation model grid was 54 x 54 x 7 (20,412 active cells). The revised field performance history match, obtained using the updated geologic model, resulted in significant improvements in individual well performance matches.

Initial Simulation Development Sensitivities with Revised Model

Full-field simulation runs were completed to evaluate various developments of horizontal and vertical CO_2 WAG injection wells. The most effective configuration was determined to be one in which horizontal CO_2 WAG injectors were positioned in down-structure locations (oriented approximately parallel to structural strike) in combination with vertical WAG injection wells in structurally higher locations. The simulation runs indicated vertical permeability restrictions in the lower reservoir would limit vertical distribution of injected CO_2 into lower intervals if horizontal injection wells were used. Application of horizontal CO_2 injection wells was therefore effective in down-structure locations where the majority of reservoir pore volume lies below the original oil-water contact.

Based on the new development sensitivities, the western horizontal well (SCU 7C11H) was reoriented to conform to local reservoir quality trends. The simulation model forecasts indicated this would result in a more rapid production response to CO_2 injection.

Updated project forecasts were then used to aid final design of surface facilities and finalize well conversion/workover strategies prior to implementation of CO_2 injection. After completing the revised reservoir modeling during 1996 the estimated incremental oil recovery for the CO_2 project was expected to be 10.4% of the original oil in place (OOIP).

Simulation modeling was used to assess uncertainties in key input and operating parameters on production profiles/reserves for project risk analysis. The project team identified major uncertain elements having forecast impact. These were grouped into three major categories:

(a) Reservoir characterization/heterogeneity/sweep efficiency;

(b) CO_2 process efficiency/target oil volume; and

(c) Well completion efficiency/injectivity (with the greatest focus on horizontal well completion effectiveness).

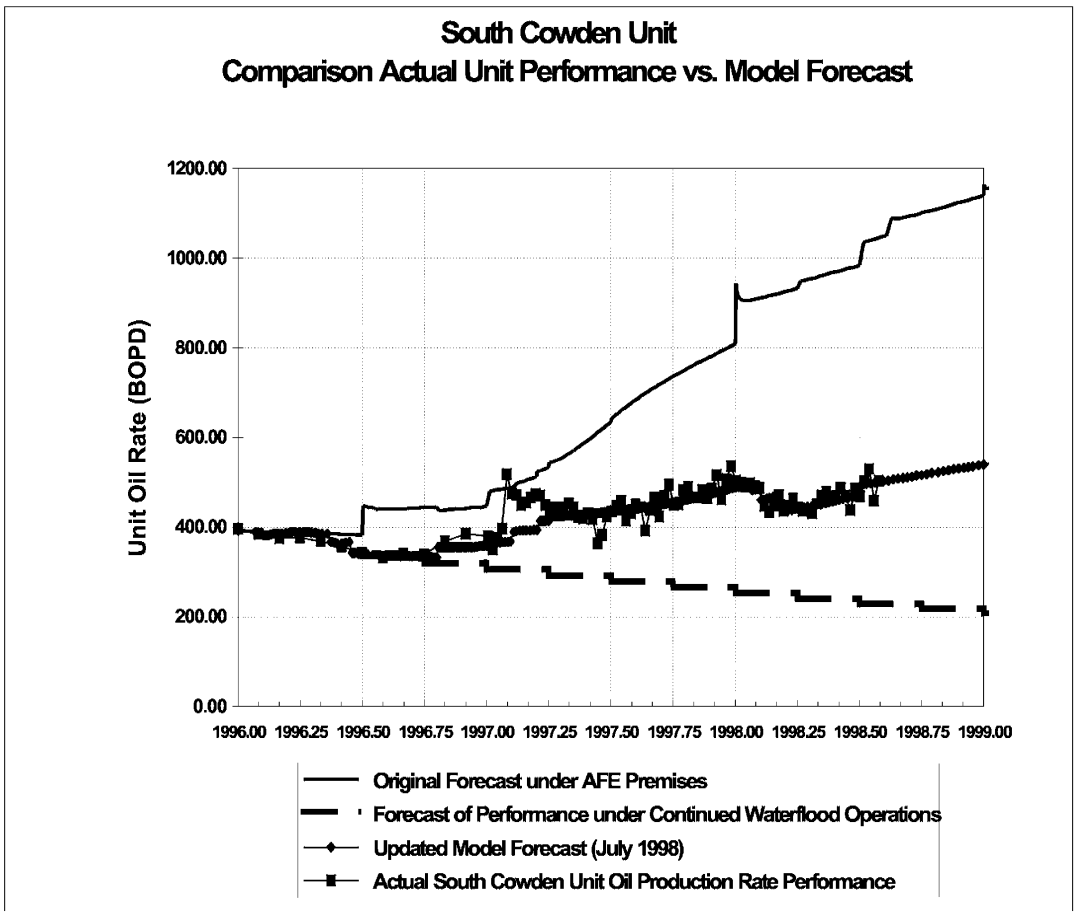
Project forecasts would be updated as implementation proceeded with data on actual injectivity and flood response. The need for additional wells would be determined based on observed flood response and updated simulation model forecasts.

A number of sensitivity runs investigated the effects of CO_2 injection strategy on project performance. Incremental oil recovery vs. WAG ratio results showed some mobility control would be needed to optimize recovery efficiency after CO_2 breakthrough. A small amount of water injection alternating with CO_2 suggested significant improvement in recovery efficiency compared to continuous CO_2 injection. Subsequent increases in WAG ratios suggested smaller increases in oil recovery. While the maximum oil recovery was obtained at a WAG ratio of approximately 2:1, the time required to inject a given total volume of CO_2 was significantly longer at this high WAG ratio. A variable WAG ratio, using an initial CO_2 slug of 7-12% hydrocarbon pore volume (HCPV) followed by increased water/gas ratio, as the flood matured, was the most economically attractive WAG injection strategy.

Updating Performance Predictions

The initial revised model, discussed above, was completed in 1996. In subsequent years during Budget Phase II, model updates were made annually to incorporate the exact project development and operating schedule. The model was adjusted to reflect the details of the actual locations, completions, and timing of newly drilled, reactivated, and recompleted wells in the CO_2 flood project area. To illustrate how the initial performance compared with original predictions, figures below show comparisons for the first two years of CO_2 flooding.

The figure below shows actual Unit performance to mid 1998. The model forecast for performance under original implementation schedule and under actual project schedule is also shown.



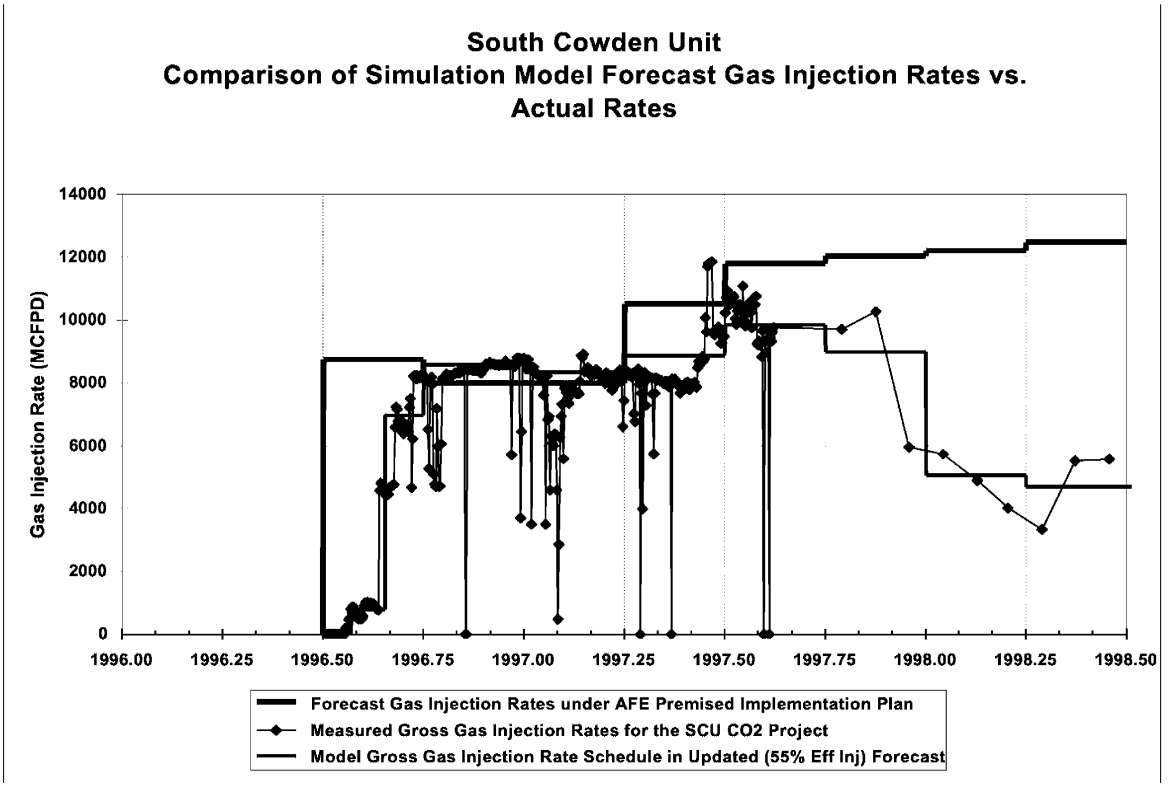
The original schedule premised all drilling, well work, facilities upgrades, etc. for the project to be completed by July 1, 1996. This was the start date premised for CO_2 injection. While all new wells were drilled and completed as scheduled, the actual startup of injection and production operations was delayed in some wells due to well testing, conducting profile surveys, etc. Reactivation of several shut-in producers was also delayed several months due to logistical considerations.

Of significant note, however, was the productive capacity of several reactivated production wells. These were either new wells drilled immediately offsetting abandoned wells with poor casing integrity, or wells re-entered in the mid 1990s that were previously temporarily abandoned. The new or re-entered wells were designed to increase offtake for the lease for the CO_2 project. Rates were initially significantly less than premised in the original forecasts (based on the productivity prior to shut-in or offset wells).

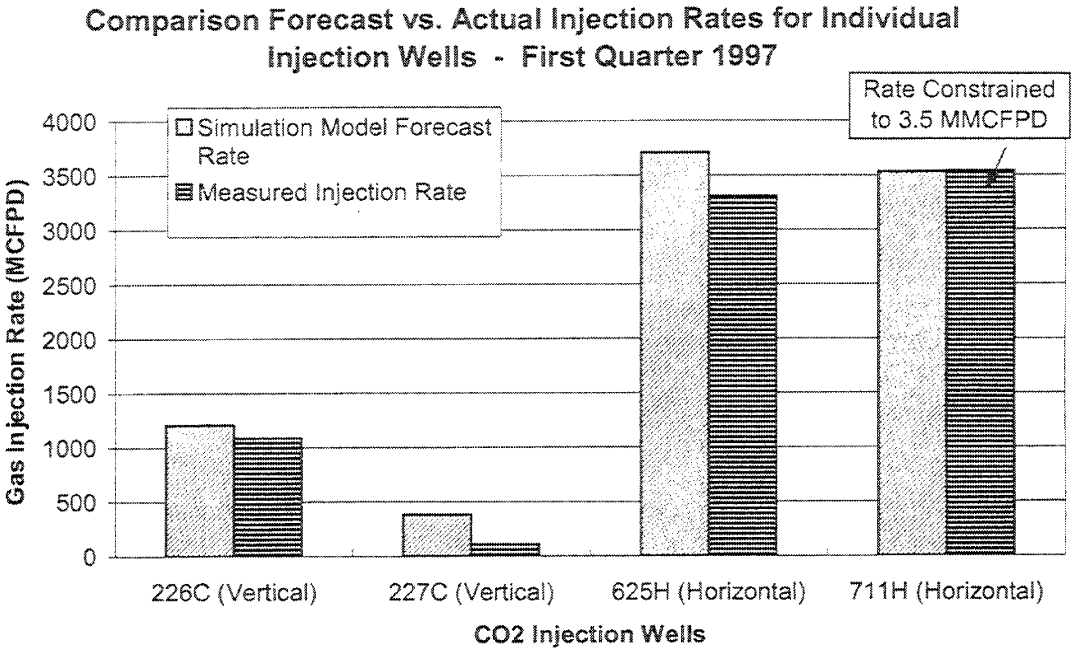
These variances in project operations and the delays in the project implementation schedule, compared with the originally premised development plan, had an unexpectedly large impact on the first twelve months of CO_2 flood response.

Appendix A

The figure below shows simulation forecasted gas injection rates, with a comparison of actual CO_2 injection during the first few years of project operations. The actual and forecast rates agree fairly well, however the actual injection schedule lagged the premised forecast by about three months.



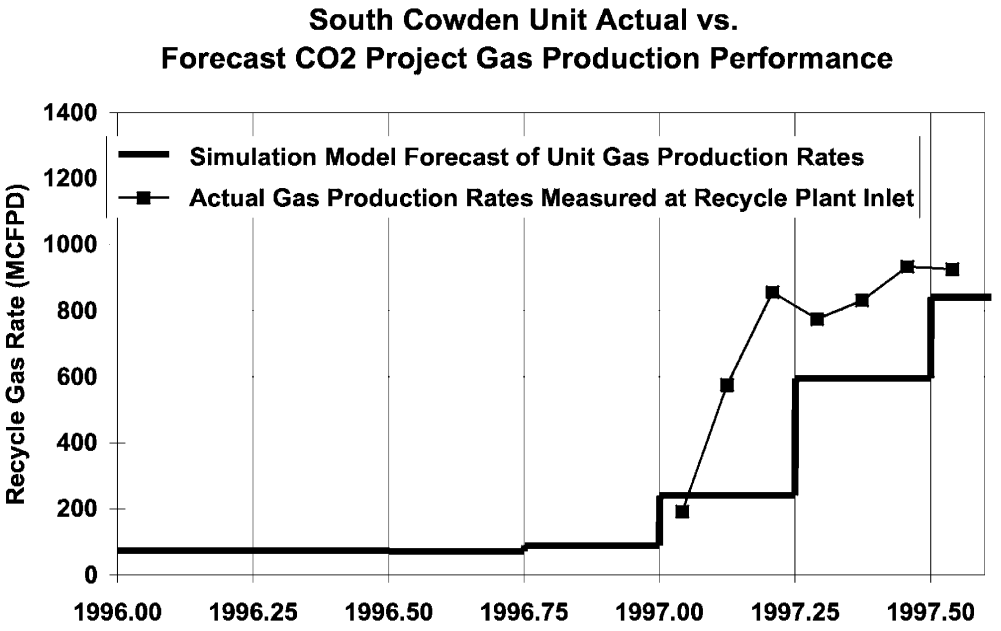
The figure below shows a comparison of forecast versus actual injection rates for the individual CO_2 injection wells in the project during the first quarter of 1997.



The relative injection rates of the two horizontal wells can be compared with injection rates into the two vertical wells. This indicates the improved injectivity observed from the horizontal wells. Note, however, poorer quality reservoir is observed in Tract 2 where the two vertical wells were placed. Also, one horizontal well (7C11H) was rate constrained to 3.5 million standard cubic feet per day (MMscfd) because most of the injected fluid was observed, after injection logging, leaving one short interval at the toe of the well, and indicating a probable fracture or thief zone. Subsequent falloff testing and injection profile surveys confirmed a possible fracture at this point in the horizontal Well 7C11H.

The figure below compares the actual monthly produced gas rates to the forecast gas production rates up to mid 1997. Actual gas production was slightly higher than the simulation model forecast.

Appendix A



Based on results of model forecasts versus actual field performance seen to mid 1997, individual well responses, and injection profile data, remedial actions were recommended at that time to remedy suspected problems with injection profiles and inadequate production capacity in certain wells.

Specific recommendations were planned for implementation during third quarter 1997 and 1998 to stimulate selected wells and conduct additional conformance work to improve injection profiles in the CO_2 injection wells.

As can be seen in 1997/1998, it was apparent the overall initial flood response had not been encouraging. Several wells were not injecting or producing as expected, resulting in a poor overall CO_2 response.

The history matched model, incorporating poorer producing well productivity, poor in zone injection and overall poor CO_2 processing and throughput in the Upper San Andres suggested that unless a significant redevelopment was undertaken to improve the flood the economics and reserves predicted would not be achieved.

Overall "in-zone" injectivity throughout the lease averaged 55%. The majority of the "in zone" CO_2 injection being achieved in well 6C25H horizontal well, with little or no in-zone injection in vertical CO_2 injection wells.

APPENDIX B

Surface Facilities Installation

Appendix B

I

INDEX

Summary
Purchase Land, Install Perimeter Fence and Hydrogen Sulfide (H_2S) Monitors
Transportation of Purchased CO_2
Construct/Operation Compression Facilities
Installation of Injection Runs at Headers and Wellheads
Installation of Fiberglass WAG System
Installation of H_2O and CO_2 Manifold
Upgrade Production Facilities
Injection System Replacement
Cathodic Protection
Installation of SCADA Equipment

Summary

Budget Phase II required surface facilities upgrades to handle the carbon dioxide (CO_2) processing from the development.

A thirteen-mile pipeline was installed to transport CO_2 to South Cowden from the Central Basin CO_2 supply line. A CO_2 re-cycle compression facility was installed to handleup to 8.6 million standard cubic feet per day MMSCF/D (after upgrades). Injection lines were installed to each CO_2 well. A water alternating gas (WAG) injection manifold was installed to centralize distribution of injectant. A new Tract 6 satellite production facility was installed to deal with increased CO_2 production. Water injection distribution pipelines were upgraded. Modern metering and safety monitors were installed. The purchasing of some private lots in the southern part of the lease reduced costsassociated with right of way and injection line installation.

Purchase Land, Install Perimeter Fence and Hydrogen Sulfide (H_2S) Monitors

All of the required private lots in Section 17 of the South Cowden Unit were purchased during the summer of 1996. The sixth lot could not be obtained for a reasonable price; hence, the lot was not purchased. Purchase of the land was anticipated to reduce costs associated with right of way and damages for installation of injection lines and production flow lines.

Extra precautionary monitors and alarms were installed along the lot line to protect the owner. This was discussed and approved by the Texas Railroad Commission (TRRC) to meet Rule 36 requirements.

The main 250-acre tract of land where CO_2 flood facilitiesare located was leased until the purchase of the land was finalized in late 1996.

Twenty-one hydrogen sulfide (H_2S) monitors were installed and are operational. Additional monitors were placed behind the private lot that could not be purchased. If H_2S is detected by any of the monitors, an alarm is sent via radio to the Phillips Petroleum Odessa office South Cowden Unit (SCU) Supervisory Control and Data Acquisition (SCADA) computer, which in turn sends a message to an operator on-call who will have an alpha-numeric pager. If the operator on-call cannot be reached, a list of people will be called until someone acknowledges the alarm.

Construction of the perimeter fence was completed. The fence was constructed to prevent public entrance into the project area, provide protection from exposure to H_2S and protect against vandalism. The fence was completed after all of the private lots were purchased.

Transportation of Purchased CO_2

CO_2 is supplied to South Cowden Unit Project via a 13-mile Odessa lateral connecting South Cowden field with the Central Basin CO_2 Supply Line. The lateral is owned by Morgan & Associates, but is operated by Enron Liquids Pipeline Company, who also operates the Central Basin CO_2 Supply Line. The six-inch diameter Odessa Lateral is designed to deliver up to 20 MMCFD to the South Cowden field. The South Cowden Unit project was expected to require up to 15 MMCFD of CO_2 during the initial years.

Construct/Operation Compression Facilities

Phillips has entered into an equipment purchase and contract gas compression services agreement contract with Production Operators, Inc. (POI) which includes equipment, installation, operation and maintenance of the recycle compression facility. Phillips provided a location and access road. South Cowden Unit and the adjacent Emmons Unit, will own all materials and equipment with the exception of the driver/compressor unit, the glycol reboiler unit and the contactor vessel unit, which will be owned by POI.

Certain tie-ins to the intake and discharge headers, fuel gas, waste water, condensate, and data collection systems were provided by Phillips, who also provided fuel/purge gas and electricity and will be responsible for the sale or disposal of waste water and/or condensate. Phillips has also constructed both produced gas and compressed gas lines for their Unit, and supplied the necessary gas meters. Costs and expenses for the operation and maintenance of the meters will be charged to a joint account for the two Phillips and Fina operated units.

The unusual and particularly beneficial aspect of the Compression Facility Agreement lies in the sharing of installation and operating costs by SCU and Emmons Units. Under normal operations, each Unit would have separately negotiated their own compression arrangements; however, the combined facility allowed for the reduction of installation and operating costs for both Units.

Production Operators, Inc. (POI) completed construction of their re-injection facility on June 21, 1996. The facility was initially equipped with a 330 horsepower (HP) Caterpillar Natural gas engine

/ Ariel compressor package rated up to 1.0 MMscf/d, and includes a Glycol gas dehydration skid for removing water from the produced gas prior to re-injection.

Significant CO_2 production commenced during the fall of 1996 in Wells Nos. 705, 6-22, 6-24 (RC-3), 6-03 and 6-07. The compression/recycle facilities were necessarily started up in December 1996, with the recycle gas being injected primarily in Well 226W. The CO_2 recycle compression facilities have been in continuous operation since this start up date. As part if the redevelopment in March 2000, the compressor was upgraded to handle up to 4.5 MMSCF/D CO_2.

Installation of Injection Runs at Headers and Wellheads

Installation of injection runs to all four of the CO_2 WAG injection wells was completed during August 1996. Installation of injection runs to the water injection wells were completed prior to injection initiation in Wells Nos. 5-02, 8-18, and 5-08.

Installation of the injection facilities was completed in July 1996, along with construction and installation of the H_2O and CO_2 (WAG) manifold. Since completion of the manifold with the CO_2/water meters, the meters were necessarily modified to improve CO_2 measurement and control.

The replacement of the old water injection system was completed with the installation of the lateral to injection Well No. 5-02.

Installation of Fiberglass WAG System

Installation was completed on the new fiberglass WAG system to the four CO_2 WAG injection wells. Installation consisted of approximately 5600' of 2" and 2400' of 3" 2500-psig fiberglass pipe.

Installation of H_2O and CO_2 Manifold

Construction and installation of the H_2O and CO_2 (WAG) manifold was completed. The injection manifold consists of eight (8) 2" stainless steel injection runs, and will accommodate the four SCU WAG wells, three future lease line wells, and one spare. The injection chokes on each injection run are fully-automated and control the volume of water or CO_2 going to each WAG well.

Upgrade Production Facilities

Construction of the new Tract 6 Satellite facility was completed. A new production header, production separator and test separator were installed. These were tied into the Tract 6 main battery. As the CO_2 content of produced gas increases in SCU producing wells, individual wells were rerouted and tied into the new Tract 6 satellite facility. A second test separator was installed at the Satellite 6 location. The additional test separator allowed more frequent testing of producing wells.

Appendix B

Injection System Replacement

Replacement of the old water injection system was completed. Replacement consisted of the installation of 2000 psig fiberglass pipe in the following lengths and sizes: 5100' of 4", 3200' of 3", 1600' of 2-1/2" and 11000' of 2".

Cathodic Protection

Logging runs using a Cathodic Protection Evaluation Tool (CPET) were made in the SCU #6-20 and #7-05 wells. A cathodic protection deep anode bed was installed near the SCU #6-20 well and both wells logged first without cathodic protection and then logged with the cathodic protection system turned on.

Evaluation of the collected data from the well logs determined the cathodic protection system for protecting casing against external corrosion will not be beneficial. The activity was therefore eliminated. A decision not to install the fieldwide cathodic protection was made during fourth quarter 1996.

Installation of SCADA Equipment

The SCADA system was installed. WAG injection manifold pressures and flow rates are being sent to the SCADA computer located in the Phillips Petroleum Odessa office, along with various alarms. Installation of producing well pump-off controllers was completed. Well performance and status will also be sent via radio to the SCADA computer.

A new software package (Genesis) was configured and installed. The new software eliminated the reoccurring problems of measuring and controlling the amount of CO_2 injected into each well.

APPENDIX C

Drilling and Workover Activities

Appendix C

Summary

Budget Phase II activities followed the original project development plan to 1999. This included drilling several new wells, re-activating others, and conversions to water injection.

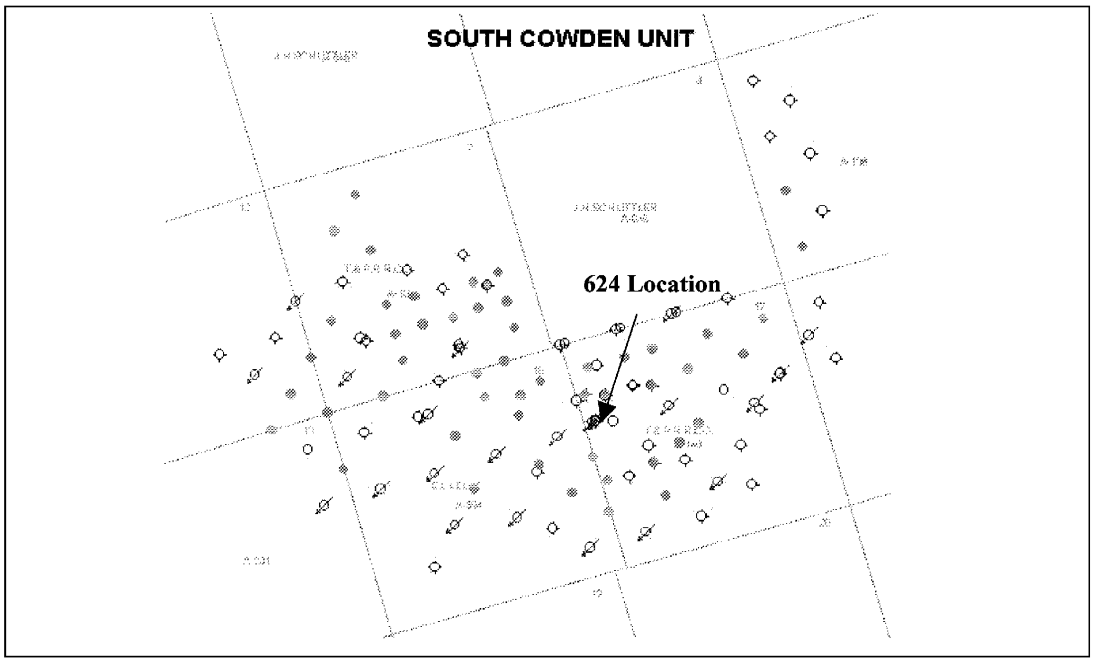
In addition to the original development plan, work was implemented between 1997 and 1999 where several wells were worked-over to improve productivity and injectivity. Producing wells were acid stimulated to improve offtake, several carbon dioxide (CO_2) vertical injection wells were worked to improve in zone injectivity.

Overall these additional activities did not prove successful in improving CO_2 processing in the Upper San Andres. This led to a cessation of the original development plan while alternative developments were evaluated. This eventually led to the Year 2000 redevelopment where CO_2 processing was improved through use of lateral and conformance technologies.

Discussed below are individual well drilling, conversions and workover activities to theend of 1999.

Drill, Core, Complete, Test, and Evaluate Well RC-3 (SCU 6-24)

The third reservoir characterization well (RC-3) was given the well number South Cowden Unit (SCU) 6-24. It was drilled in November and December 1995. The location is shown on the map below.

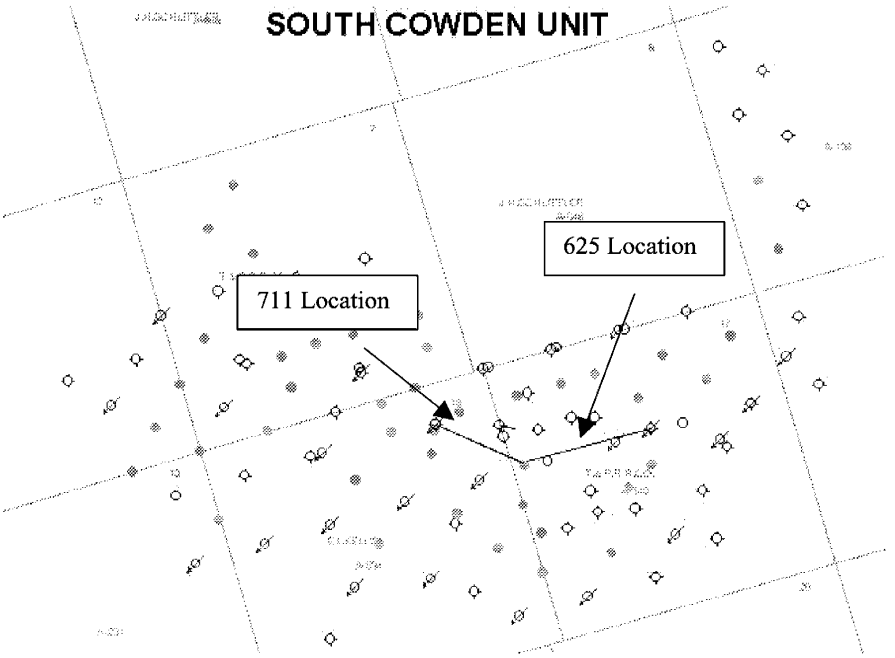


The well was perforated in the lower E, upper D, and C zones. Details of the coring and subsequent analysis are provided in the Reservoir Characterization section.

Appendix C

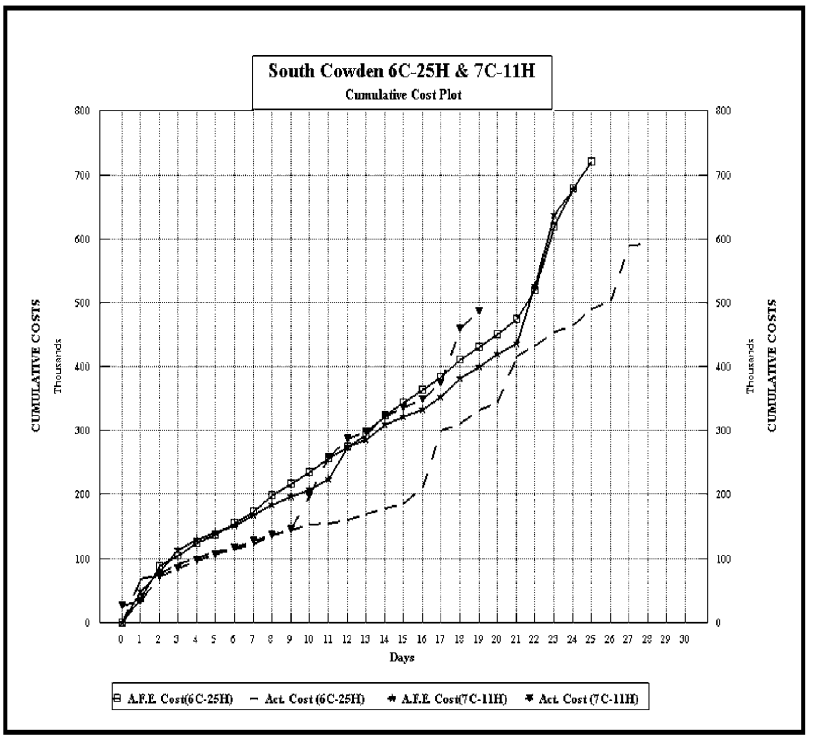
Drilling of Horizontal CO_2 Injection Wells (6C25H and 7C11H)

The drilling and completion operation for horizontal CO_2 injector 6C25H (East well) began March 17, 1996. It was completed in 28 days. Due to contractor and equipment problems, this was completed four days after the estimated completion date. The drilling operation, however, for 7C11H (North west well) began April 14, 1996 and was completed in 20 days. The experience gained in the first well was a major factor in completing the 7C11H four days ahead of the estimated completion date.



It was also attributed to the combination of good communications, contractor preparation / experience, and the experienced drilling supervisor staff.

Appendix C



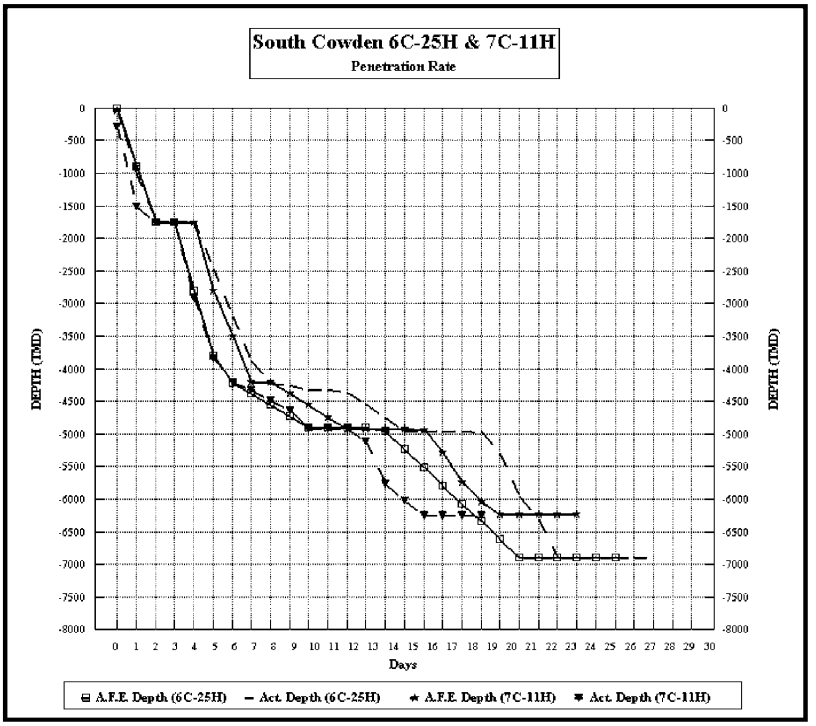
The design and actual drilling results of 6C25H and 7C11H are illustrated below.

Appendix C

South Cowden Unit

Horizontal Injection Wells 6C25H and 7C11H

Design vs. Actual results



Appendix C

	6C-25H Design	**6C-25H Actual**	**7C-11H Design**	**7C-11H Actual**
DLS	12°/100'	10.96°/100' (AVG)	12°/100'	11.39°/100' (AVG)
Azimuth	76° East of True North	75.83° East of True North (AVG)	65° West of True North	65.27° West of True North (AVG)
KOP	4212'	4212'	4195'	4195'
Casing Placement	4684' TVD / 4889' TMD (81.2°)	4681' TVD / 4955' TMD (83°)	4671' TVD / 4915' TMD (86°)	4672' TVD / 4907' TMD (87°)
Csg Pt Deflection Length from Vertical	440'	462'	447'	476'
Curve Length	751'	743'	751'	775'
90° Lateral Depth	4706' TVD / 4963' TMD	4690.29' TVD / 5180' TMD	4672' TVD / 4945' TMD	4675' TVD / 4970' TMD
Lateral Length (measured from csg shoe)	2000'	1935'	1303'	1337'

NOTE: All depths are measured from the rotary kelly bushing (RKB) height.
6C25H surface elevation: 2934'
7C11H surface elevation: 2935'
Surface locations were 70' apart.

Operations were modified for horizontal drilling. The drilling contractor provided a mud system (such as a flow line cleaner, agitators, rolling lines, and a 200 barrel (bbl) pre-mix pit) to effectively condition the polymer mud system. In addition to the rig specifications, a centrifuge conditioned and maintained the mud. This optimized polymer mud properties. The polymer-based mud was used because of hole sweeping efficiency, thin filter cake production, solids retention time, friction coefficient in relation to reducing hydraulic pipe drag, viscosities, filtrate loss, and gel strength characterizations.

Optimizing these characteristics enhanced penetration rates, hole conditioning and limited stuck pipe potential. In addition, triplex pumps with sufficient horsepower reduced interference with measurement while drilling (MWD) pulse readings and maximize mud motor performance.

The directional drilling of curve and lateral sections required several bottom hole assembly (BHA) adjustments. The bit was a tungsten carbide insert toothed tri-coned roller cutter bit with tungsten carbide inserts around the bit circumference to provide stabilization while directionally sliding the drill string, and maintaining the bit and hole in gauge. Directional measurements were acquired by utilizing a positive pulse MWD system. Details on the BHA are included below.

South Cowden Unit Horizontal Injection wells
Bottom Hole Assemblies

Curve Section	
4 2" premium drill pipe 16.6 #/ft (to surface)	3 2" drill pipe S-135 13.3 #/ft (to surface)
X-over sub (3')	3 2" AHevi water drill pipe (1200')
4 2" AHevi water drill pipe 42 #/ft (900')	3 2" drill pipe S-135 13.3 #/ft (3000')
X-over sub (3')	4 3/4" monel collar (32')
4 2" Premium drill pipe 16.6 #/ft (1000')	4 3/4" monel collar (32')
6 2" monel collar (30')	Float sub / orienter combo (4')
6 2" monel collar (32')	4 3/4" Positive Displacement Pump 1.25° deflection (22') Designed for rotating and sliding
Float sub (3')	6 1/8" tungsten carbide 3 coned bit Modified for directional drilling (1')
6 3/4" Positive Displacement Pump 1.25° deflection (22')	
8 ¾" tungsten carbide 3 coned bit Modified for directional drilling (1')	

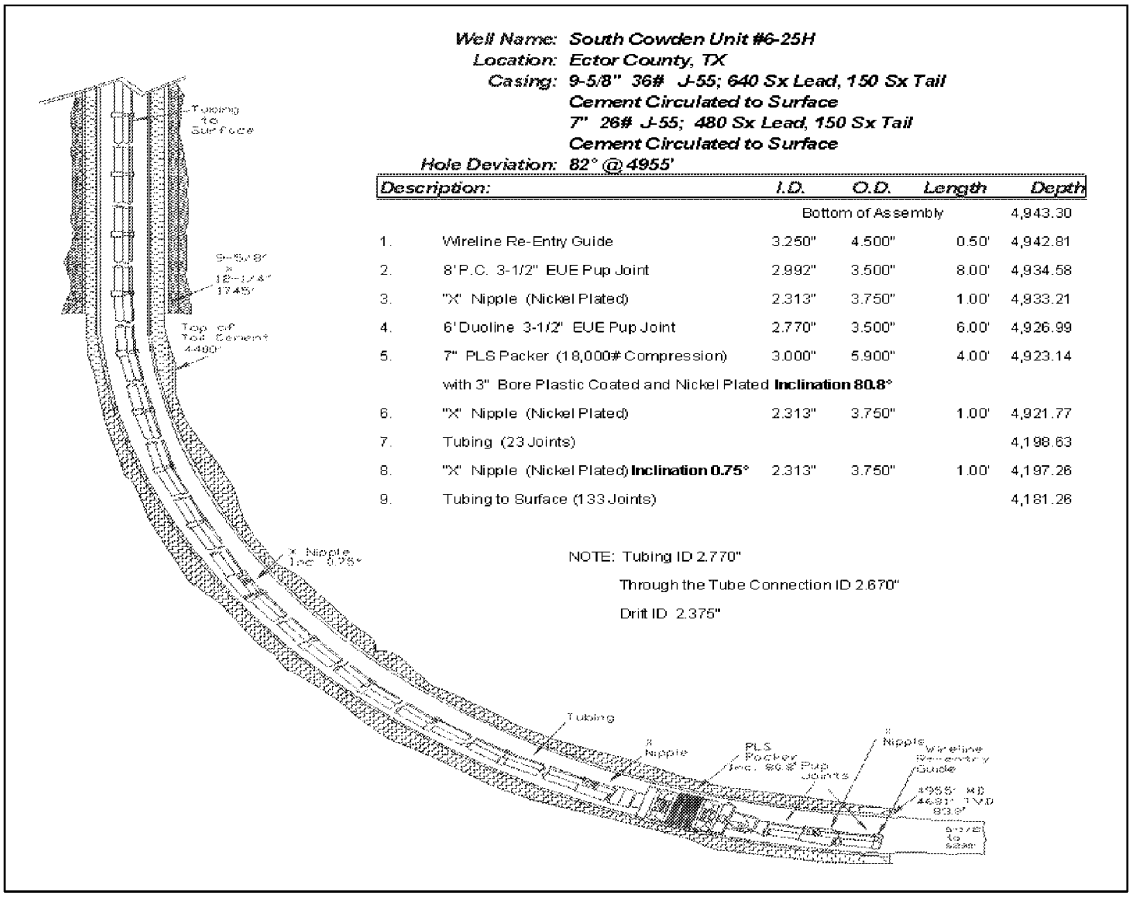
NOTE: Monel collars were utilized in the drill string to eliminate MWD magnetic interference. The MWD system is set within the collars of the drill string.

Appendix C

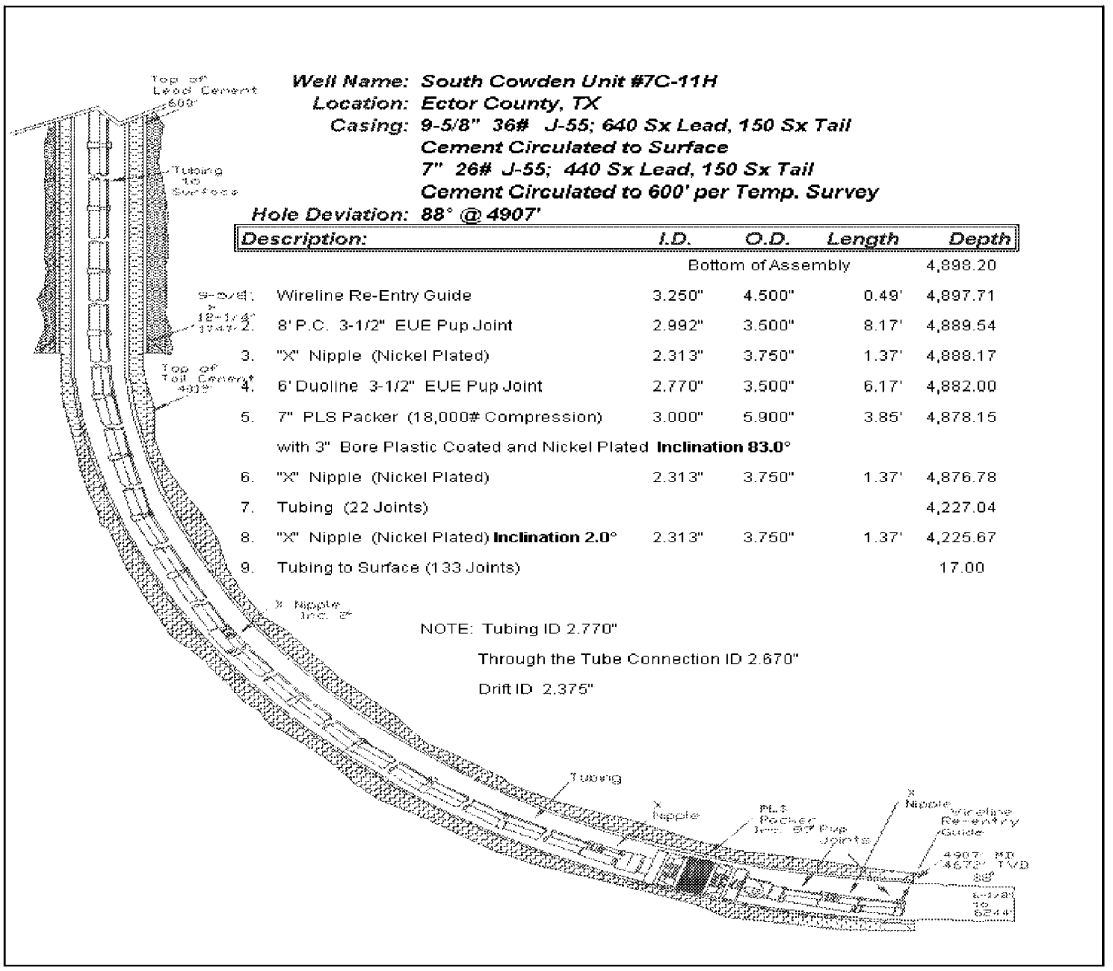
The wells were designed mechanically to optimize injection performance and longevity. Both wells were designed to accommodate 9-5/8", 36 pounds per foot (ppf), J-55 surface casing, 7", 20 ppf, J-55 production casing through the curve, and a 6-1/8" openhole injection interval. The production casing was designed with 7" tubulars to accommodate 3-2" production tubing. The 20 ppf casing weight was utilized for additional corrosional wear allowables rather than for withstanding predicted injecting pressures.

The cased curve trajectory was designed to accommodate 125' of production casing within the San Andres producing interval. This optimized packer-setting depths in relation to casing corrosion exposure.

The 3-2" injection tubing maximized injection rates. The entire downhole injection system was designed to resist CO_2 corrosion effects alternating with water. Therefore, the tubing was lined with fiberglass inserts and the injection packer coated internally with plastic and externally with nickel plating. The injection tree, for corrosion purposes, was constructed of solid stainless steel. The completion string is illustrated below.



Wellbore Schematic Horizontal Injection Well 6C25H



Wellbore Schematic Horizontal Injection Well 7C11H

Testing of Horizontal Injection Wells Nos. 6C25H and 7C11H

Prior to being placed on CO_2 injection, injection profile surveys and falloff tests were conducted under water injection. The objective was to verify acceptable distribution of injection along the lateral section and determine mechanical condition and completion efficiency. Both horizontal sections were drilled only into the E zone interval of the San Andres.

Injection Testing while under Water Injection

Cardinal Survey performed a profile on 6C-25H. The profile tool consisted of a continuous flow meter, quartz pressure sensor, temperature surveys, capacitance and gamma ray probe conveyed on 1.25" coiled tubing. Good results were obtained even though the survey was performed at low injection rates under a small formation pressure differential.

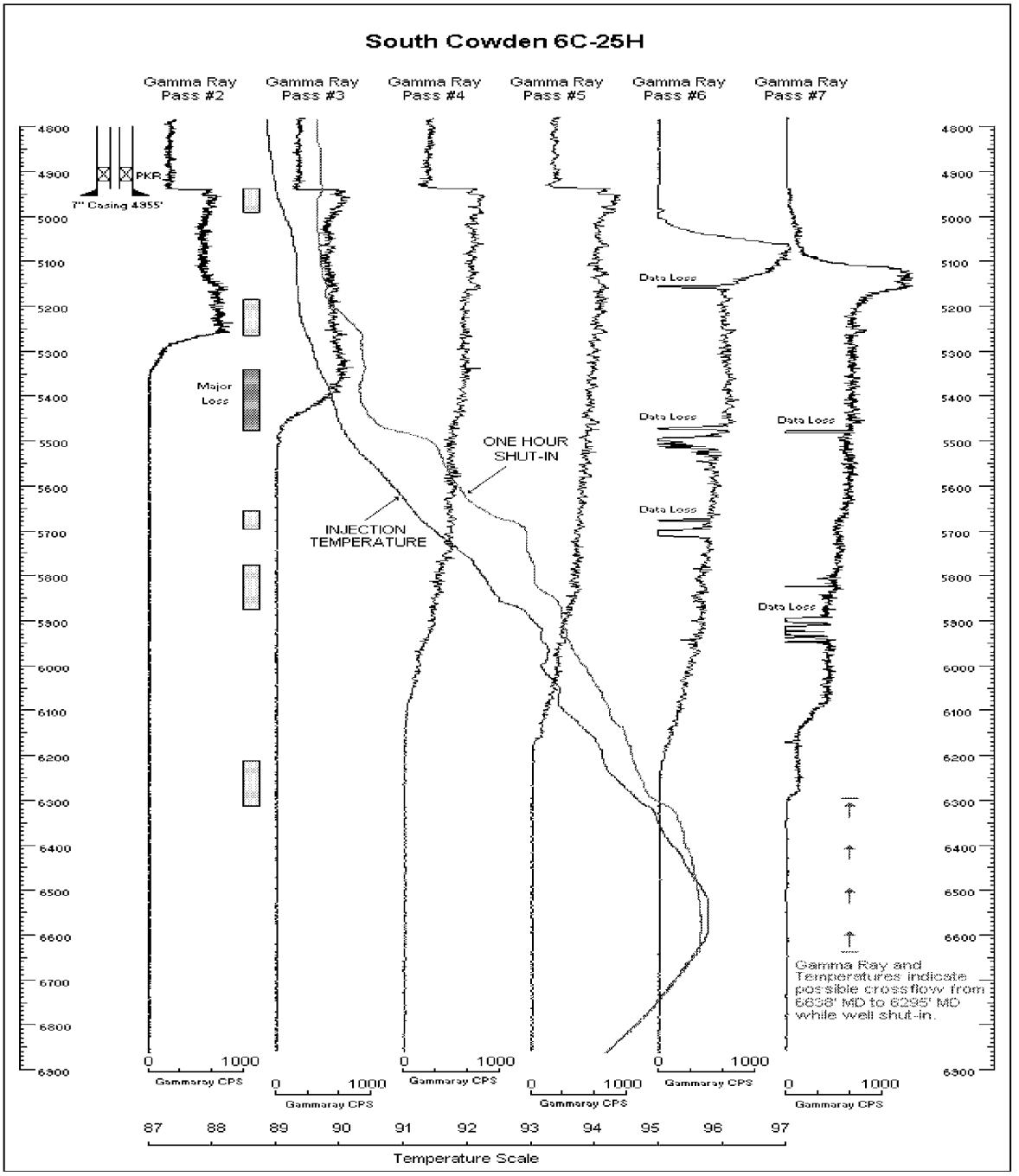
Injecting and shut-in temperatures indicated fluid movement through the horizontal openhole interval to approximately 6600' wireline (WL) depth, with a major fluid loss at 5340'-5480' WL. The logs indicated lesser fluid losses at 4940'-4990' (near the casing shoe), 5185'-5275', 5655'-5695, 5775'-5870' and 6210'-6295' WL. The gamma ray passes and tagged fluid measurements supported these conclusions. The one-hour shut-in temperature log and concurrent gamma ray pass indicated crossflow from 6638'-6295' WL during shut-in. It was also noted that the trailing edge of the tagged interface showed tubular buildup.

Repeated temperature passes showed a 1-1/2 degree cooling anomaly from 6650'-6800' WL. An influx of fluid coming from the formation into the end of the horizontal section appeared to be the most plausible cause. Because no other conclusive data from other log sensors could be found, it was concluded influx rate was equal under both shut-in and flowing conditions. Initial injection profile logging results are presented in the figure below.

Injection pressure measurements and a pressure falloff test were performed. Initial pressures matched closely with simulation model predictions along the horizontal traverse. Permeability data derived from radial flow periods matched with history-matched permeabilities in the simulation model. The length of effective interval (250') taking fluid, derived from model matching, agreed with injection profile survey results. The pressure falloff results indicated a good stimulation was obtained from the coiled tubing acid wash over the horizontal section.

Based on the favorable profile and fall off analysis, 6C25H was placed on CO_2 injection during early August 1996 and slowly brought up to a bottomhole injection pressure slightly below the calculated formation parting pressure of 2600 pounds per square inch (psi). This is equivalent to 0.57 pounds per square inch per foot (psi/ft) fracture gradient (determined by a micro fracture test on SCU Well 6-21 during 1994. The injection rate stabilized close to expected simulation model forecasts.

Appendix C



Memory Logging Results Under Water Injection, Well 6C25H

On 7C11H Halliburton used a different procedure for the profile work. The logging was performed using coiled tubing with wireline run simultaneously. A Y-block and coiled tubing side-entry assembly was attached below the spot valve. The tool consisted of positive/negative gamma ray and temperature tool. A slug of one gallon of radioactive gel with 50-micron sand was used rather than the standard injection procedure of 1 cubic centimeter (cc) per station. A flowing temperature log and velocity shots were used to determine fluid entry.

Results of the second injection profile survey were somewhat ambiguous and difficult to interpret. Halliburton's interpretation indicated injection fluid movement throughout all but the last 150 feet near the toe of the horizontal interval. Based on the flow rate and the gamma ray logs, in-house interpretation of the results indicated most of the fluid entering a fracture or high permeability zone at the toe of the well, between 6025' and 6100'. These logging results are presented in the figure below.

Injection pressure measurements and a pressure falloff test were performed. This test did not show the same behavior as 6C25H. The test showed early linear flow behavior rather than early radial flow as with 6C25H.

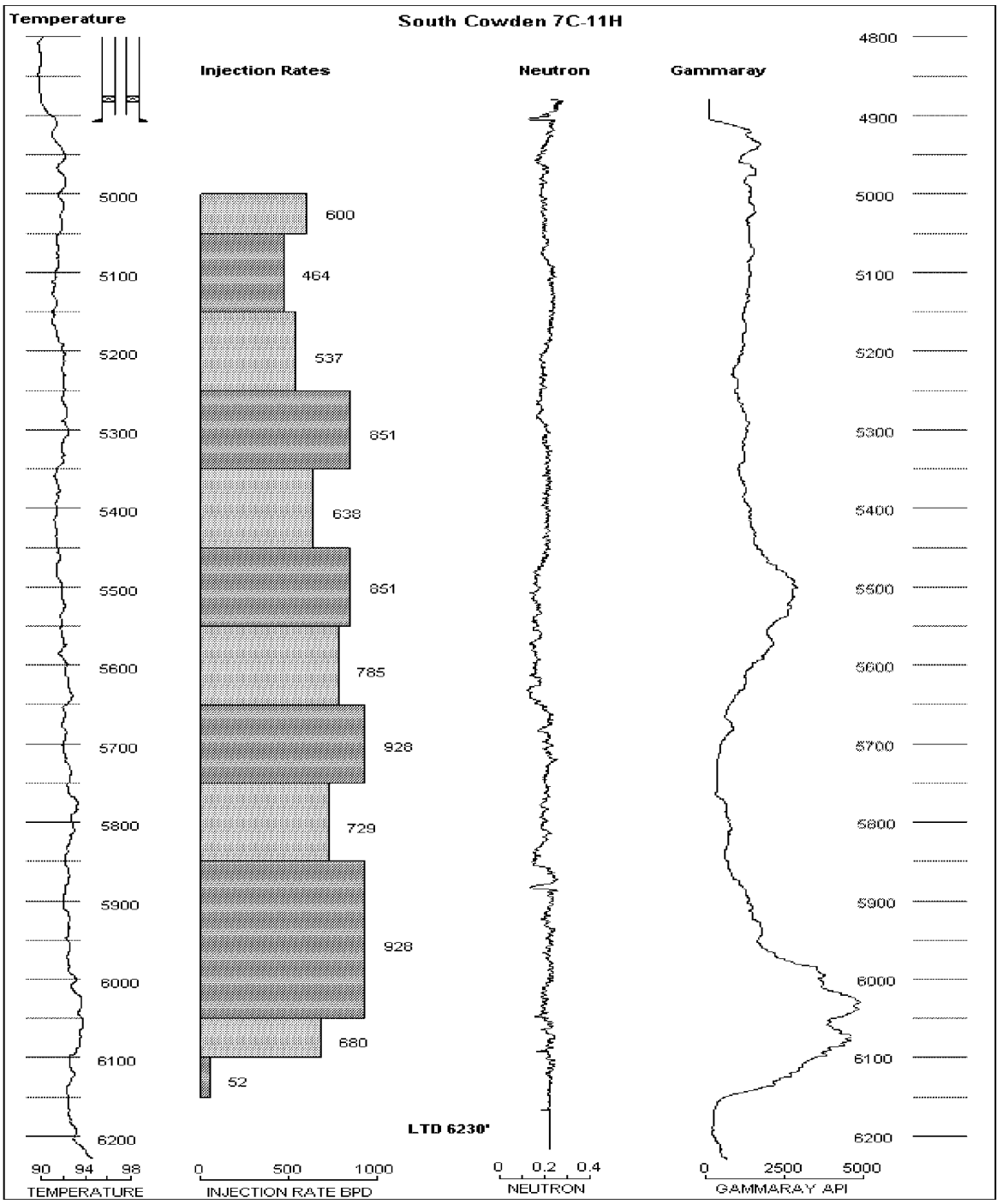
7C-11H was drilled approximately normal to preferential parting direction indicated in earlier micro-frac tests conducted in two reservoir characterization wells, 6-21 and 6-23. The injection pressure during testing was limited to several hundred pounds per square inch (psi) below parting pressure while on water injection.

One possible explanation for the falloff test behavior was that 7C11H may have intersected a parting plane from one of several nearby old injection wells. Before proceeding to CO_2 injection, it was decided to run a step rate test followed by an additional falloff test. The step rate test showed a shift toward linear flow behavior and possible fracture extension above 2600-psi bottomhole injection pressure.

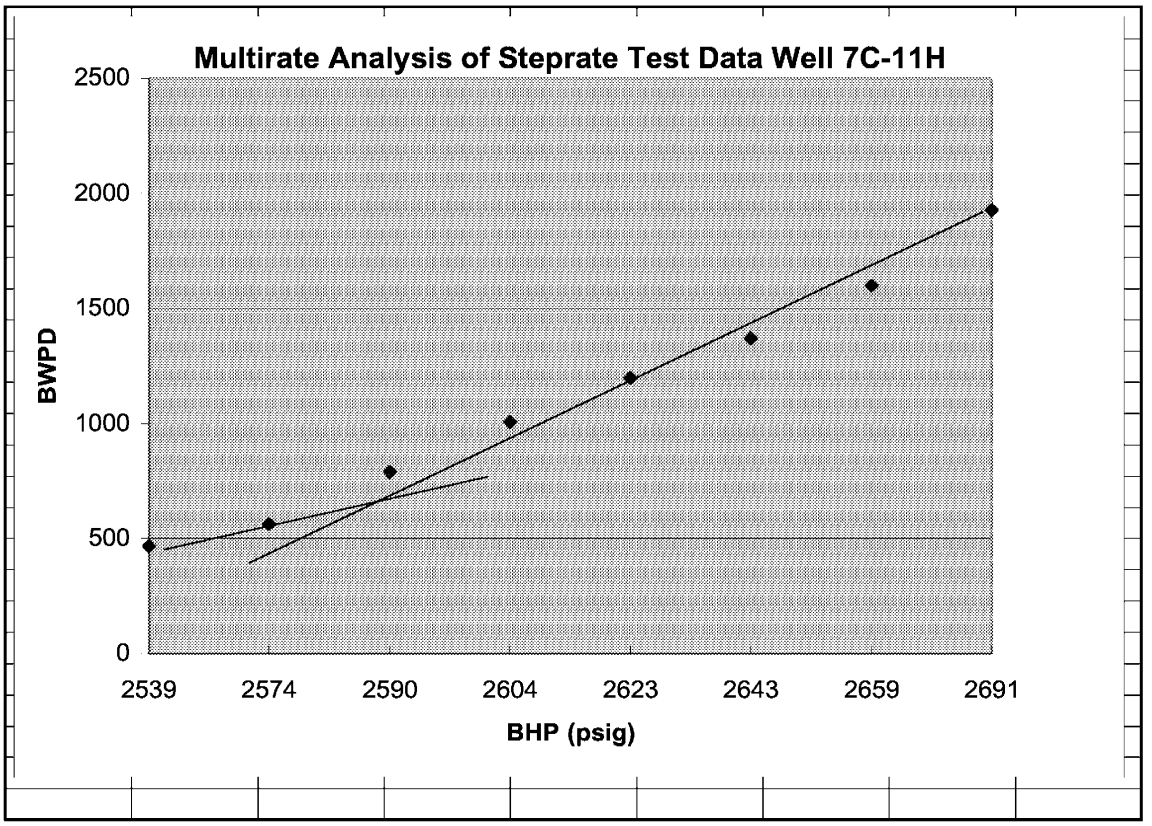
Analysis of step rate test data on Well No. 7C11H (shown below) indicated a significant shift in injection behavior at bottomhole injection pressures above 2590 pounds per square inch absolute (psia) at 4675 feet true vertical depth (TVD). Some fracture propogation extension was indicated at injection pressures above this level.

For this reason, the initial surface injection pressure during CO_2 injection was set at 1050 pounds per square inch gauge (psig). The surface CO_2 injection pressure of 1050 psig would keep bottomhole injection pressure at or slightly below 2590 psia at 4675 feet TVD.

Low volume CO_2 injection in 6C25H and 7C11H commenced in early August 1996, following the pressure and injection profile testing. Higher volume CO_2 injection commenced in 6C25H on August 14, and in 7C11H on August 29 1996.



Coiled Tubing and Wireline System Results under Water Injection, Well 7C11H



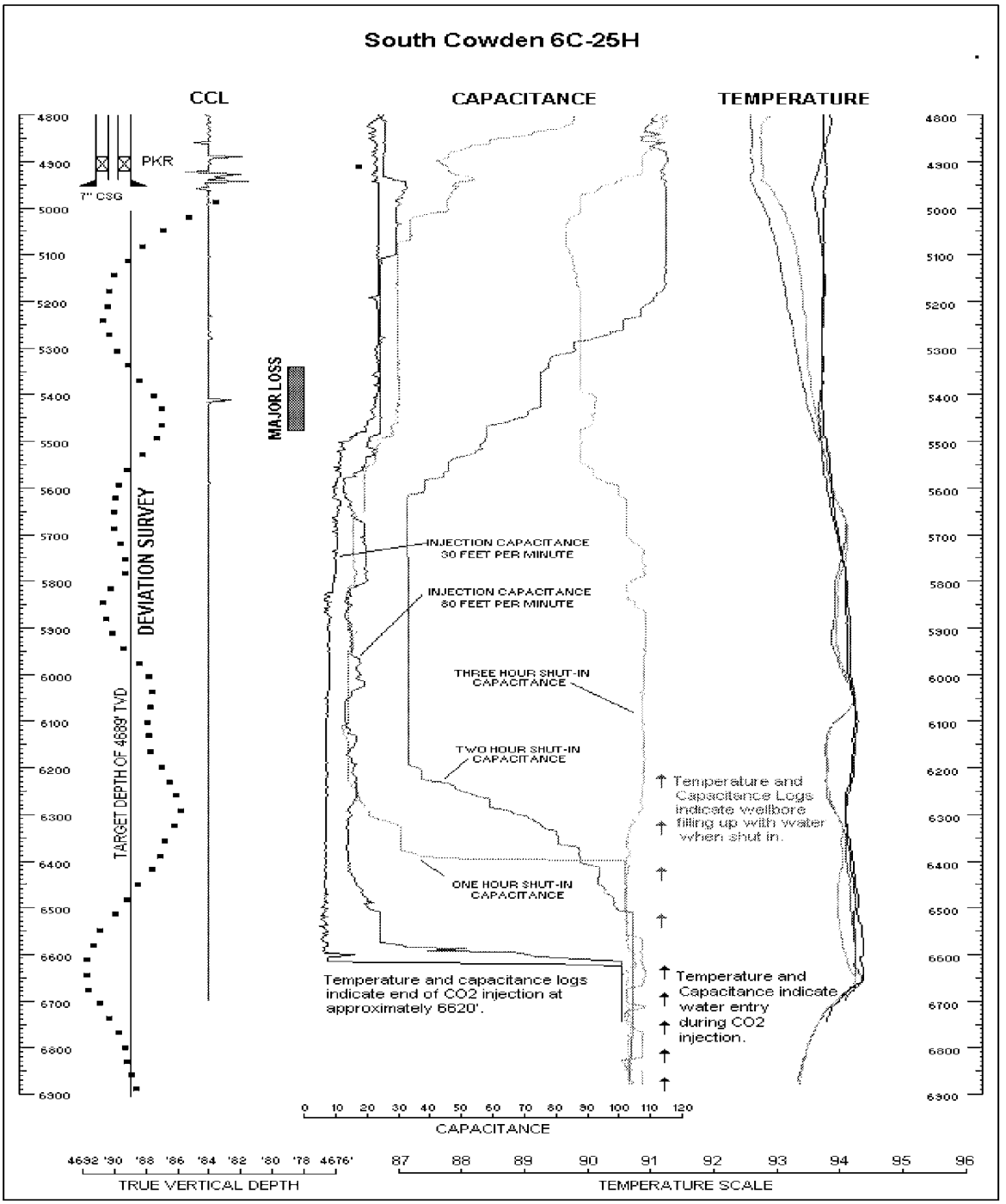
Multi Rate Analysis of Step Rate Test Data, Well 7C-11H

Injection Testing while under CO_2 Injection

An additional injection profile survey was performed on both horizontal wells during initial CO_2 injection. These injection profile surveys evaluated CO_2 injection performance and determined lateral/vertical distribution of injected fluids.

The 6C25H injection profile indicated fairly uniform distribution of injection fluids under CO_2 injection, confirming the profile logging results under water injection. Injecting and shut-in temperature runs indicated fluid movement throughout the horizontal, openhole completion out to approximately 6620' WL, with a major loss at 5340'-5480' WL in Well 6C25H. Injecting temperatures, shut-in temperatures, injection capacitance, and shut-in capacitance logs indicated water cross flowing from the end of the horizontal section to approximately 6620' WL. Shut-in capacitance logs showed a progression of water entering the wellbore from about 6880' WL and an area near the major fluid loss at 5340'-5480' WL, filling the low areas of the wellbore, as indicated by the deviation survey. The last shut-in capacitance run showed the water level had risen to a point where it was spilling-over into the middle section of the wellbore. Results from injection logging during CO_2 injection in Well 6C25H are shown below.

Appendix C

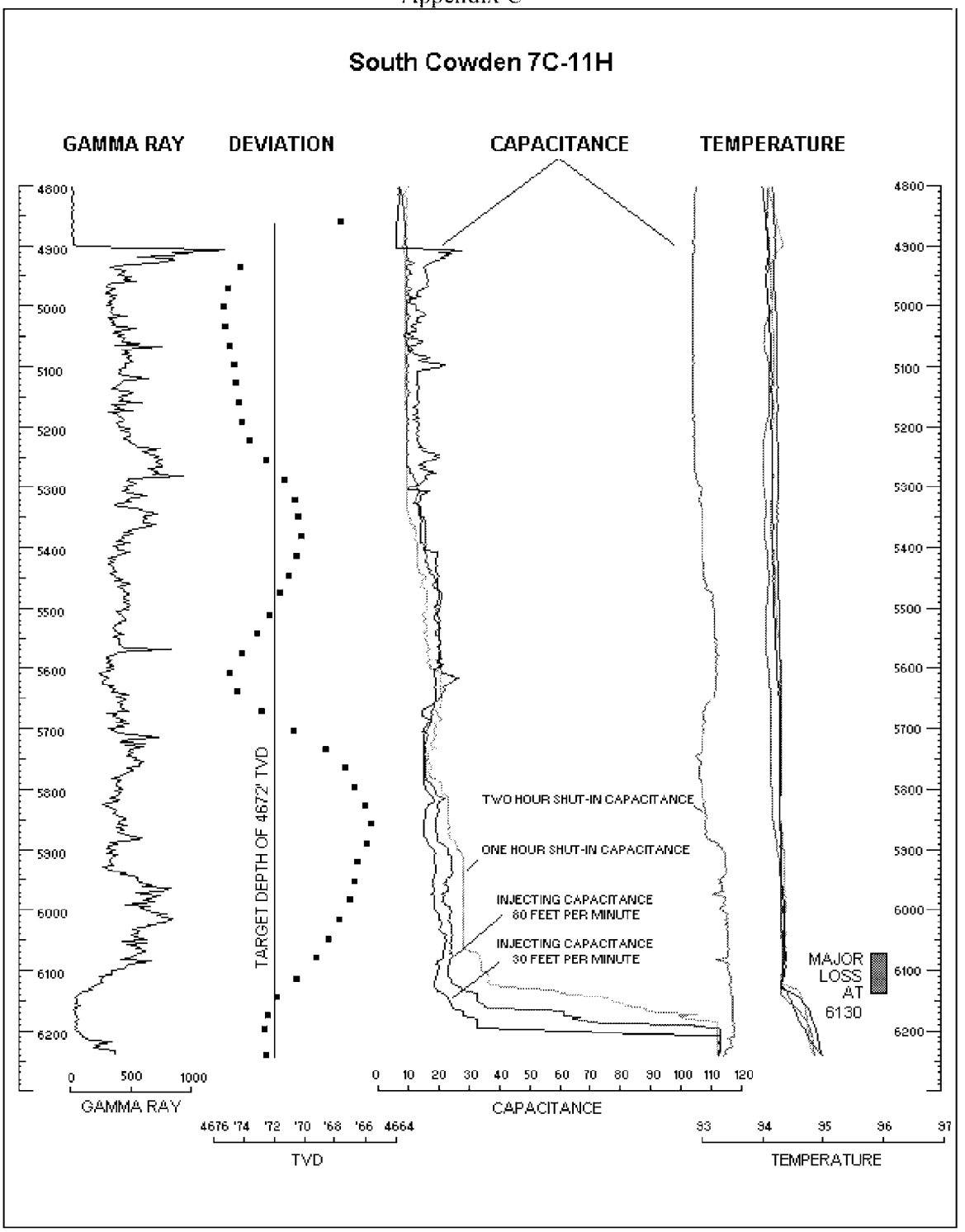


Memory Logging Results under CO_2 Injection, Well 6C25H

In contrast, 7C11H injection and shut-in temperature passes indicated possible fluid loss out the toe of the horizontal section. This interpretation was based on only a .25-degree temperature change at the toe of the horizontal section. This minor change in temperature could also be caused by a rising water level in the horizontal wellbore. The capacitance log run indicated a CO_2/water interface at approximately 6210'-6200' WL while the well was on injection. The one-hour shut-in pass showed the interface had moved to approximately 6140' WL. The two-hour shut-in pass indicated water throughout the entire openhole section. It is important to note the tools were not centralized; therefore, these readings do not necessarily prove the wellbore was full of water. They merely indicate there is some amount of water in all the openhole section during the shut-in periods. These logging results are included in the figure below.

A fracture had been suspected during the falloff and step rate testing, and was further suggested by this profile log under CO_2 injection.

A third injection profile was run during October 1997 to confirm identified losses in the toe of the well. Gamma ray and temperature logs confirmed major loss in two distinct intervals in the well's toe, at 6100-6110' and 6150-6180'. The log also indicated a possible internal diameter (ID) restriction at 5400'. This well was placed back on CO_2 injection following this survey. The information obtained from the injection profile logs was used for designing mobility control measures to prevent out of zone injection through the toe region of 7C11H. Options evaluated included use of packers, crosslinked polymers, cement, foamed cement, monomers and sodium silicates.

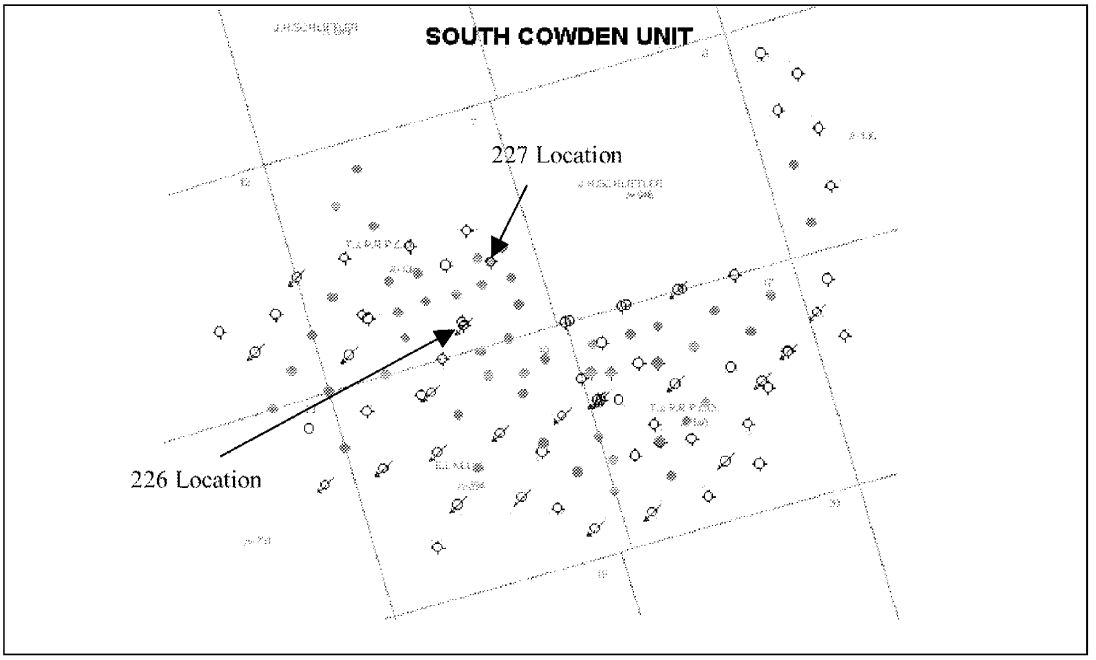


Memory Logging Results under CO_2 Injection, Well 7C11H

Appendix C

Drill Vertical Wag Injection Wells

Two vertical CO_2 water alternating gas (WAG) injection wells were planned for Tract 2 in the northwest portion of South Cowden Unit (see figure below). Tract 2 is in the structurally highest part of the unit, where Zones C through A, underlying the main pay zones E and D, are oil bearing. The vertical injection wells in this area of the field would permit direct flooding of all four zones with CO_2, and improve the oil recovery of the project.



The proposed injection wells SCU 2-26W and 2-27W were drilled in December 1995. The SCU 2-27W was temporarily completed as a producing well from zones C through F. Wells 2-27W and 2-26W were waiting for pipeline and injection facilities to be complete prior to CO_2 injection.

Injection in Vertical Wag Injection Wells Nos. 2-26W and 2-27W

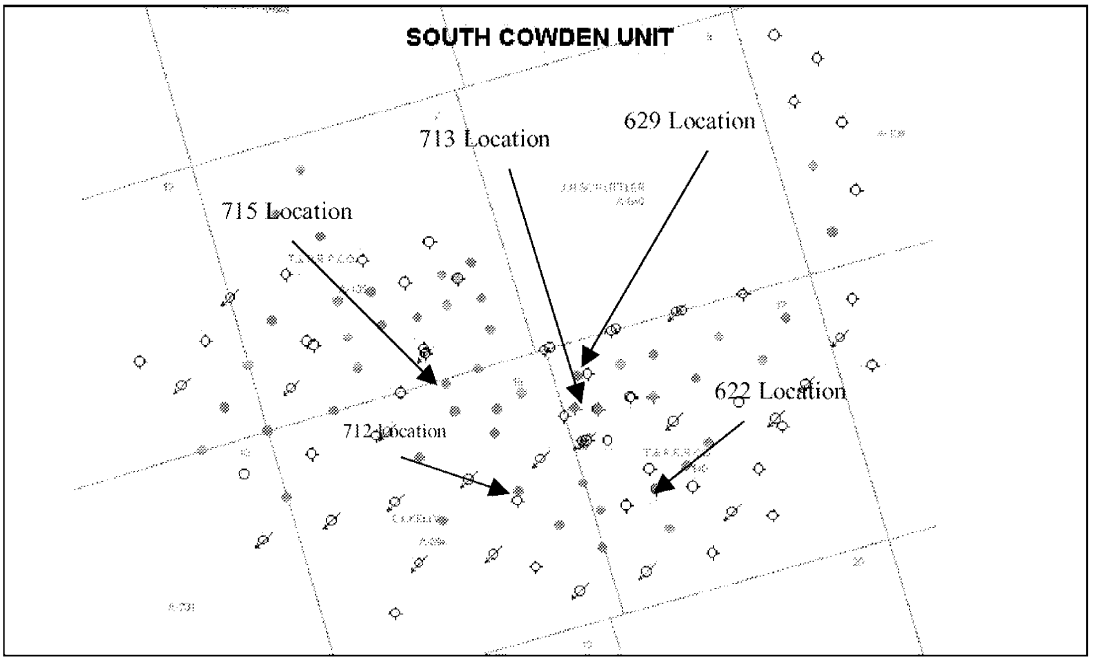
Water injection commenced in vertical WAG injection Wells Nos. 2-26W and 2-27W in early July 1996. Bottom-hole pressure surveys were obtained in both wells during late July, immediately prior to commencing CO_2 injection.

CO_2 injection began July 19, 1996 in Well No. 2-26W, at an initial wellhead pressure of 890 psig and injection rate of 200 thousand standard cubic feet per day (Mscfd). CO_2 injection commenced July 22, 1996 in Well No. 2-27W, at an initial wellhead pressure of 1000 psig and injection rate of 200 Mscfd.

CO_2 injection surveys in these wells were performed in November 1997. Both logs indicated CO_2 entering the perforated intervals, but with at least some behind pipe or out of zone injection down to the layers below the B zone.

Drill Multiple Producing Wells

Two additional production wells, SCU 6-22 and SCU 7-12, were drilled and completed in November and December 1995. The well locations are shown below. These wells were needed to drain areas of the field offsetting horizontal injection wells and to replace plugged and abandoned wells.



Two new producing wells were drilled during fourth quarter, 1996, Wells Nos. 7-13 and 7-15. Well No. 7-13 was drilled as a replacement well for plugged and abandoned production Well No. 7-06. Well 7-15 was drilled to improve the spacing in the northern portion of Section 18.

South Cowden Unit Well No. 6-29 was drilled to a total depth of 4808' during September 1997, with a plugback depth at approximately 4755'. This is a replacement well for Well No. 6-01, which had irreparable casing damage. Well No. 6-29 was completed October 18, 1997, testing 8.5 barrels of oil per day (BOPD), 183 barrels of water per day (BWPD), 1.2 thousand cubic feet gas per day (MCFGD), and 9% carbon dioxide (CO_2), with fluid level at 27 joints. A shut-in bottomhole pressure (BHP) and buildup test measured BHP of 2233 pounds per square inch gauged (psig) recorded after a 72-hour shut-in. The pressure extrapolated to infinite shut in time is 2455 psig (P*).

Convert Five Wells for Water Injection

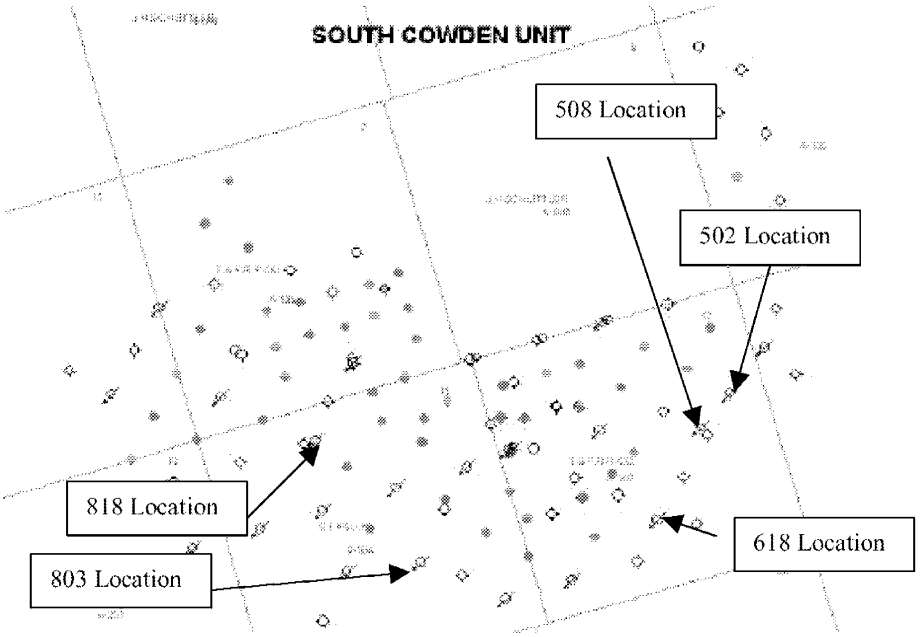
Operations commenced in 1996 to convert SCU Wells Nos. 5-02, 5-08 and 8-18 to water injection.

Appendix C

Well	----------BEFORE-------- BOPD	BWPD	MCFD	---------- AFTER----------
SCU 5-02	12	735	3	Injecting @ 690 BWPD and 720 psig (Mar., 1997)
SCU 5-08	6	60	3	Injecting @ 250 BWPD and 560 psig (Nov., 1996)
SCU 8-18	6	176	1	Injecting @ 518 BWPD and 750 psig (Nov., 1996)

During third quarter, 1997, SCU Wells Nos. 6-18 and 8-03 were converted to water injection.

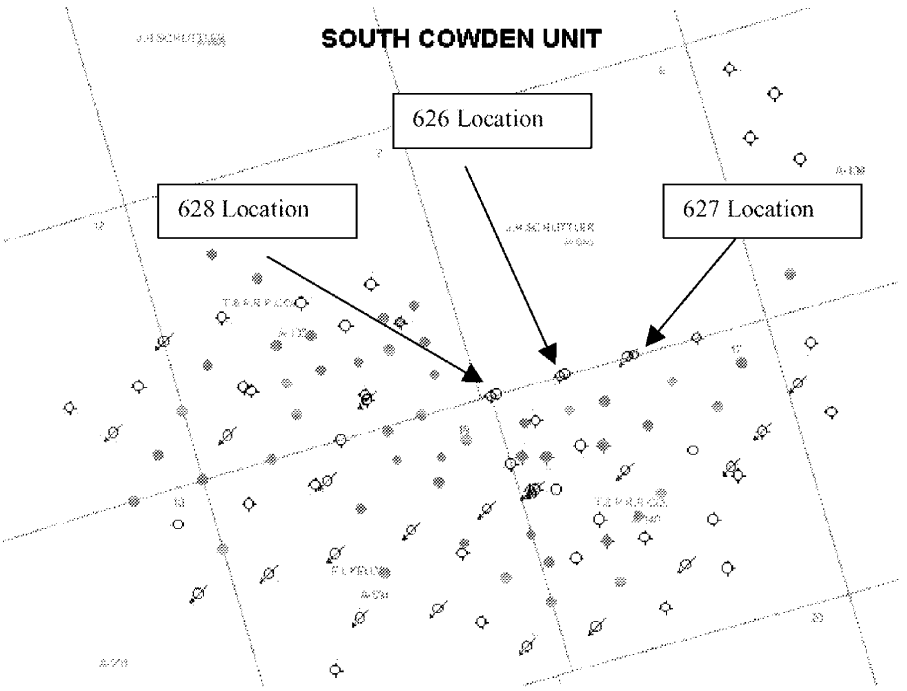
	----------BEFORE----------	---------- AFTER----------
SCU 6-18	Shut-in	Injecting @ 248 BWPD and 480 psig
SCU 8-03	Shut-in	Injecting @ 300 BWPD and 680 psig.



Drilling/Logging/Conformance Three vertical WAG injectors along South Cowden Unit boundary (Wells 6-26, 6-27 and 6-28)

Appendix C

During fourth quarter 1996, three vertical WAG injection wells were drilled along the north boundary with the Emmons Unit. The reservoir in this area is higher on structure; the advantageous structural position provides additional pay sections.



Vertical WAG injection Wells Nos. 6-26W and 6-27W were placed on water injection during January 1997. Injection profile surveys were run while on water injection during early February 1997.

6-26 Injection Profile Surveys while on Water Injection

The February 1997 injection survey on Well 6-26W indicated communication between a Grayburg water sand at 4344'-4355' and casing perforations 4568'-4572' and 4578'-4582'. The Grayburg formation is immediately above the San Andres. During the shutin period, the log indicated flow from the water sand entered the wellbore through the perforated interval at a rate of 35 barrels per day (BPD) and was cross-flowing into another perforated interval 4592'-4726'.

The injection survey suggested the perforated intervals below 4700' (4709'-4711', 4716'-4718', and 4724'-4726') were taking approximately 15% of the injection water with evidence of downward channeling. Downward channelling refers to behind pipe communication to the lower layers of the San Andres. A remedial workover was proposed to squeeze the intervals 4709'-4726' and 4568'-4582' in an effort to limit out-of-zone injection.

A workover was performed during early April 1997, to conventionally squeeze cement into the lower thief zone (4709'-4726') below a retainer at 4701', then cement squeeze the upper

perforations at 4568'-4582'. After three attempts to squeeze the upper zone a pressure test held and the well placed back on water injection.

A subsequent water injection profile survey was run during June indicating the upward channel wad successfully plugged. However, virtually one hundred percent (100%) of injected water was going out the bottom of the well, into the lower layers of the San Andres.

A foamed cement job was therefore performed during late June to stop the out-of-zone injection, and the well reperforated across the E/upper F zones (4618'-4638'). The job appeared to be successful, and the well placed on carbon dioxide (CO_2) injection.

On September 19, 1997 a follow-up injection profile was obtained, at an injection rate of 424 BWPD at 400-psig surface injection pressure. Velocity calculations indicated eighty-three percent (83%) of the fluid entered the new perforations at 4618'-4638'. Eighteen percent (18%) of the fluid, however, was entering old perforations at 4631'-4637'. No flow was detected inside the pipe past 4642'.

Temperature logs indicated channeling up to 4580', and down below 4648', with approximately 70% of fluids leaving new perforations at 4618'-4628'. Although the profile was not perfect, the foamed cement job was deemed a success and CO_2 injection commenced.

6-27W Injection Profile Surveys while on Water Injection

In February 1997 a water injection log run on Well 6-27W indicated 50-60% leaving the wellbore through the perforated interval 4746'-4748'. The injection survey indicated limited water injection occurring above 4686'. A foamed cement job was therefore planned during third quarter pending evaluation of a similar procedure in Well 6-26W.

A foamed cement squeeze was performed on Well 6-27W in early August utilizing 300 sacks of "premium plus" cement foamed with a 10-pound/gallon density. The cement was drilled out and the well re-perforated at 4608'-4628'. The well was stimulated, and placed back on injection.

A follow-up injection profile survey was performed during mid-September 1997. The velocity shots indicated 82% of the fluid leaving the new perforated interval 4608'-4628', with 18% exiting the old perforations at 4631'-4635' and no flow inside the pipe past 4642'. Temperature logs indicated 70% entering through the new perforated interval, with 6% movement down to 4648' and an upward channel to 4580' (not out of the San Andres interval). Although not perfect, the profile indicated a correction of the out-of-zone injection, and the well was placed on CO_2 injection during October 1997.

6-28W Testing: Tracer and Interference Testing (Not included in original DOE funding)

The third lease line injection well, 6-28W, was drilled in this area. During the drilling oil shows were seen in the drilling returns. When placed on a production test during late January, however, the well produced 70% CO_2 from the produced gas. This initiated concern CO_2 was bypassing reservoir rock through the suspected fracture in the toe region of the northwesterly

horizontal WAG injection Well 7C11H. In order to test this hypothesis, a tracer test was attempted between the two wells.

On February 25, 1997, a sulphur hexafloride (SF_6) tracer test was run in Well 7C11H, with produced gas samples taken from Well 6-28W. A trace of tracer gas was found in Well 6-28W within nine (9) hours of starting the test. No additional SF_6 tracer, however, was encountered upon subsequent monitoring. Although first results seemed to confirm a direct channel exists from the 7C11H to Well 6-28W, further investigation of the sampling techniques indicated sampling might have been tainted, rendering the test results inconclusive.

Further testing was therefore planned to further delineate remediation possibilities.

Because of the east-west preferential fracturing direction, determined by micro-fracturing tests in Wells 6-21 and 6-23, there was additional concern CO_2 could originate from vertical injection in Well 2-26W, almost 2000' to the west-northwest of 6-28W.

An interference test was therefore designed during September 1997 to determine the origin of the produced CO_2 seen at 6-28W. Pressure bombs were hung in the shut-in well No. 6-28W while injecting water into 7C11H.

Well No. 6-28W was shut-in at 8:00 a.m. on September 24, 1997. The downhole gauge in 6-28W was initiated at 9:53 a.m. October 2, 1997 (zero hours). Well No. 7C11H was shut-in (for injection logging, discussed above) at 21:53 on October 2, 1997 (+12 hours (hrs) 10 minutes (mins)). At 8:03 am, October 4, 1997, 2-26W was shut-in (+46 hrs 15 mins).

Pressures in 6-28W continued to build-up following shut-in of 7C11H. Pressures, however, began falling-off approximately five hours after 2-26W was shut-in. This suggested pressure interference between 2-26W and 6-28W.

This, however, was not confirmed with a final injection period on 2-26W. If a final injection period at 2-26W had been initiated and a pressure increase 5 hours later observed at 6-28W it would have confirmed communication from 6-26 to 6-28W. Unfortunately, due to operational reasons, the final injection period for 2-26W was not achieved.

An additional pulse test between Wells 2-26W and 6-28W was therefore undertaken in June 1998. The June test gave a conflicting response, suggesting no definite communication between these wells. With the lowering of injection pressures in Well 2-26W, from late 1997 onwards, the communication path seen during the October pulse test may have been eliminated.

Re-Activate Seven Shut-in Wells for Production

Seven temporarily abandoned wells were reactivated:

Appendix C

	AFTER			
	BOPD	BWPD	MCFPD	
SCU 6-20	11	75	4	Oct. 19, 1996
SCU 7-02	5	119	0	Sept 30, 1996
SCU 7-05	5	220	1	Oct. 8, 1996
SCU 7-10	1	183	17	February, 1997
SCU 2-20	0	250	0	March, 1997
SCU 6-19	0	412	0	March, 1997
SCU 8-13	0	202	0	March, 1997

Workover or Recondition Existing Wells (Not included in original DOE funding)

During fourth quarter 1996, five wells were checked for fill and acidized. During first quarter 1997, additional perforations were added to Well 6-23, and the well acidized:

	BEFORE			AFTER			
	BOPD	BWPD	MCFD	BOPD	BWPD	MCFD	
SCU 2-21	5	40	1	6	98	3	Nov. 10, 1996
SCU 2-24	7	38	1	9	63	2	Nov. 20, 1996
SCU 6-06	3	40	1	3	148	1	Dec. 12, 1996
SCU 2-08	6	90	1	13	128	1	Dec. 12, 1996
SCU 8-02	10	59	1	8	81	0	Dec. 4, 1996
SCU 6-23	1	0	48	1	249	1	March 1997

During second quarter 1997, three wells were acid stimulated. The results follow:

	BEFORE			AFTER			
Well	BOPD	BWPD	MCFD	BOPD	BWPD	MCFD	Comments
SCU 7-01	24	116	116	31	170	100	May, 1997
SCU 7-05	4	212	1	5	385	1	May, 1997
SCU 7-10	3	62	6	17	116	26	April, 1997

During third quarter 1997, fourteen wells were acid stimulated. The results follow:

	BEFORE			AFTER			
Well	BOPD	BWPD	MCFD	BOPD	BWPD	MCFD	Comments
SCU 2-01	20	107	0	41	217	7	
SCU 2-02	3	41	0	12	188	1	
SCU 2-08	3	38	0	13	147	3	

SCU 2-22	8	141	5	24	253	29
SCU 2-25	30	167	5	30	207	6
SCU 5-07	8	87	1	25	225	49
SCU 6-02	12	105	1	9	150	47
SCU 6-22	47	97	25	0	151	32
SCU 7-02	2	43	0	11	70	28
SCU 7-08	28	910	340	20	477	123
SCU 7-09	3	55	0	5	220	0
SCU 7-12	1	8	0	0	285	0
SCU 7-13	14	30	0	9	1	5
SCU 7-15	6	30	0	13	96	0

Production for the project area initially increased by approximately 75 barrels of oil per day (BOPD) and 1500 barrels of water per day (BWPD) as a result of the total clean-out program, including Wells Nos. 7-01, 7-05, and 7-10, stimulated during second quarter 1997.

Plug and Abandon Three Shut-in Wells (not included in original DOE funding)

During third quarter 1997, SCU Wells Nos. 2-16W, 6-01 and 6-12W were plugged and abandoned due to regulatory requirements (bad casing).

APPENDIX D

Monitoring Flood Performance

Appendix D

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Summary

Well production and injection volume details are maintained in a Microsoft Access database. This database may be read directly, or via the Oil Field Manager software.

Close monitoring of production data, to the end of 1999, indicated the area around horizontal injection well 6C25H had the best response to carbon dioxide (CO_2). Well 6C25H was drilled horizontally into the zone of interest, and had no indications of out of zone injection, unlike its twin well 7C11H, where a perceived fracture system was taking the majority of injected gas. Response from nearest well to the toe of 7C11H suggested it was also responding to CO_2, so some percentage of the injected CO_2 was entering the zone of interest. The majority, however, appeared to enter a fracture system and out of the targeted pay zone layers.

Other areas of the field, such as around vertical injection wells 2-27W, 2-26W, 6-26W, and 6-27W had little or no response, suggesting the out of zone CO_2 injection was contributing to the poor CO_2 processing of the San Andres upper layers. The lack of well productivity was a major concern for the flood. The total production rate from re-entered and replacement wells were lower than originally

anticipated. This resulted in a voidage in-balance in the field where productivity was not able to match injectivity.

This led to a generally increasing reservoir pressure during the early months of CO_2 injection, to levels close to fracture initiation pressure. The high reservoir pressure limited CO_2 injection where injection pressures were constrained less than fracture pressure. Conversely, in some wells, injection pressures were not constrained and induced out of zone CO_2 injection. A disposal well, 2-18, was eventually deepened to the Clearfork interval and a high proportion of produced water was injected into the Canyon/Clearfork intervals. This aided lowering reservoir pessure by reducing water injection back into the San Andres.

Several activities were performed to resolve the poor productivity from wells including acid stimulations, chemical treatments, jetting techniques and additional perforations. None of the techniques proved successful in providing a longterm productivity improvement, required to boost the production rate from the lease to lower reservoir pressure.

Overall, by the end of 1999, the lease was under-performing its predicted CO_2 response due to a combination of poor production rates, poor in zone CO_2 injection, higher reservoir pressure and a fundamental belief that the original predictions for production were too optimistic.

Reduce Reservoir Pressure, 2-18 deepening (not included in DOE funding)

Shut-in bottomhole pressure data in the South Cowden Unit (SCU) Project Area indicated reservoir pressure to be approximately 2300 pounds per square inch gauged (psig), increasing to approximately 2600 psig in the Emmons Unit to the north. Bottom-hole pressure (BHP) surveys, in wells 6C25H and 7C11H, conducted during February 1998, indicated 2614 psig and 2632 psig @ reservoir datum of -1700 (4651' true vertical depth (TVD)).

Minimum miscibility pressure (MMP) is 1200 psig. The optimum reservoir pressure for SCU CO_2 flooding is estimated at 1800 psig. Lower reservoir pressures allow injected CO_2 to occupy more reservoir volume and contact more recoverable oil by increasing the narrow pressure margin between the fracture gradient and reservoir pressure. Disposal of produced water was therefore considered the optimum solution to lower reservoir pressure. In the original development plan there were provisions for deepening wells to the lower San Andres to increase water injection capacity. The Project team, however, agreed water disposal in a lower San Andres interval would ultimately increase overall San Andres reservoir pressure. Deepening 2-18, discussed below, was therefore recommended as an alternative.

During March 1997 the project team requested interna funds to deepen, complete and equip SCU Well No. 2-18 for use as a water disposal well. Approximately 8000 barrels of water per day (BWPD) was being produced in the Unit, and reinjected. Funds were requested to deepen the plugged and abandoned SCU Well No. 2-18, for disposal of up to 5000 BWPD outside the San Andres CO_2 target interval, into the Canyon and potentially the Clearfork intervals.

At the time, three additional wells in the vicinity of the South Cowden area were being reviewed for water disposal potential, as were options to lay pipelines to other leases (both Phillips operated and non-operated), where water injection volumes are required. These options were rejected in favor of the 2-18 disposal well.

South Cowden Well No. 2-18 was successfully deepened to the Lower Clearfork interval between August 15 and September 9, 1998 and then perforated and acidized in the Canyon/Cisco and Lower Clearfork intervals on September 14. Initial injection rates were 2600 BWPD at 640 pounds per square inch gauged (psig) surface injection pressure.

Increase Productivity

One of the main concerns during initial years after implementing CO_2 injection was lack of productivity from wells. Actual offtake rates from newly drilled or reentered wells were lower than anticipated. Small withdrawal rates from producers reduced throughput throughout the reservoir, increasing average reservoir pressure and limiting CO_2 injection.

Acid Stimulation

Several wells were acid stimulated to improve withdrawal rates. Initially they seemed effective. Longer-term productivity was, however, not maintained. The longer-term effectiveness of the stimulation work is discussed in more detail in the Redevelopment Review in the attachments.

Core samples from 6-24, from various zones in the San Andres, were tested for acid solubility and reaction time at various temperatures. This revealed carbonate intervals with high anhydrite content or intervals with high clastic content tended to have slow reaction times when compared to low anhydrite carbonates. For example, upper layers in the E zone (high anhydrite content) and the interval between the C and D zones (high clastic content) had lower reaction time when compared to the low anhydrite content C zone. Sensitivities to acid treatment temperature revealed reaction times for high anhydrite content intervals could be improved by raising treatment temperature, whereas low anhydrite or high clastic content intervals reaction time was not effected by treatment temperature. The results of these lab tests are important for two reasons.

Any acid stimulation performed above fracture pressure, which would allow communication to low anhydrite content intervals, will preferentially react with those low anhydrite intervals. Therefore, any acid stimulation performed on an interval perforated in the target E zone, which had to be performed above fracture pressure, would allow open communication to lower intervals. Most noticeably this would be in the high permeability (low anhydrite) grainstone interval which is normally below the oil water contact.

To improve acid reaction times and solubility of the rock where there is a higher anhydrite content it can be heated at surface.

Appendix D

Chemical Treatments

Lack of productivity was caused, in some wells, by an increase in effective skin factor due to build up of scale and heavy end hydrocarbons in the wellbore. Therefore, a new chemical treatment was tested on SCU Well No. 7-08 on March 5, 1998.

The system was designed to address paraffin/asphaltenes, calcium carbonate, and calcium sulfate in a single application. The expense work included a paraffin/asphaltene solvent, sulfate and carbonate remover, antisludge chemicals, and an iron reducing agent. The job was applied via the casing-tubing annulus. The well showed no increase in oil production following the treatment, but daily water production increased by over 100 BWPD.

A similar sampling, analysis and chemical treatment was preformed on well-25, followed by treatments in June and early July in wells 2-02, 6-17, 7-01, 7-02, and 7-09. All treated wells improved producing rate initially, with an average liquid rate increase of 92%. All seven wells reached their target liquid rate, rates we would expect with no significant skin damage.

Wells 2-01, 2-17, 2-22, 6-14, 8-02 and 8-19 were treated between July 15 and 20, 1998. Of these six wells, five wells responded to the treatment and four wells reached their target rate.

Wells 5-07, 6-02, 6-19, 6-20, 6-24, 7-15 and 8-13 were scheduled for treatment before the end of July 1998. The two wells treated showed response to treatment and reached their target rate. The other five wells were not treated as improvements in off-take rate were observed, and no treatment was deemed necessary. Continued chemical treatments occurred throughout the project area, to improve short-term productivity. These types of treatments have proved more cost effective when compared to the acid stimulation workovers.

Jetting Technique

New technology to create short lateral boreholes in existing wellbores using coiled tubing and jetting technology had been developed. Three producing wells (1-07, 6-23 and 7-13) were jetted during October 1998. Production tests on these wells were closely monitored, and no significant gains were observed. The technology has not been used again.

Additional Perforation

Well No. 6-29 was re-perforated in the zone of interest, followed by stimulation during July 1998, to improve throughput in the area south of well 6-28. The perforations and acid stimulation increased oil production from 1 to 7 barrels of oil per day (bopd), and the total off-take rate from 17 barrels of fluid per day (bfpd) (before) to 160 bfpd (after job), but the production of both oil and water have steadily decreased to 1 bopd and 50 bwpd as of June 2001.

Limiting CO_2 injection pressure, increase water injection from 4th Quarter 1997

Appendix D

Instantaneous shutdown pressure (ISDP) data, obtained from well work during second and third quarters 1997 in Emmons and South Cowden Units, indicated the fracture gradient to be approximately 0.6 psi/ft. With this knowledge the team recommended surface injection pressures for water injection wells be limited to 650 psig and 1150 psig for CO_2 injection, within the project area. This would necessarily reducethe amount of CO_2 being purchased, and injected, but would decrease loss of CO_2 out of zone.

The project team also recommended, at that time (prior to 2-18 deepening), water injection wells surrounding the project area could exceed the recommended injection pressures to dispose of excess water in lower zones. These were in areas away from the main CO_2 development area.

The field personnel implemented the above recommendations, considerably reducing CO_2 purchase volumes. Primarily the CO_2 was still injected in the horizontal injection Wells Nos. 6C25H and 7C11H. After reviewing the CO_2 injectivity for each well, in June 1998, injection rates were increased only in Well No. 6C25H, as it was believed it was not injecting at its full capacity.

Lease Injectivity and Out Of Zone Injection

Injection profile surveys in all vertical injection wells indicated out of zone injection into the highly transmissible, and in most instances, water wet, lower layers. Either injecting above fracture pressures or acid stimulation was thought to initiate fracturing downward into the lower zone, causing waste of CO_2. Since late 1997 surface pressures for water injection wells were limited to 650 psig and CO_2 injection wells to 1150 psig, to ensure injection below fracture pressures.

Actual injection rate decreased since limiting surface pressures, most noticeably in vertical wells. The reasons for this were:

1) High reservoir pressure in the zone of interest causing lack of pressure differential between well bore and reservoir, reducing the wells capacity to inject CO_2.

2) Lack of injectivity, due either to skin damage or poorer reservoir quality than anticipated.

Horizontal injection well 7C11H was determined to have the majority of CO_2 entering the toe of the well. Methods evaluated to isolate this well section include packers, crosslinked polymers, cement, foamed cement, monomers and sodium silicates. These methods have been reviewed in detail with Phillips and service companies, but no ideal solution for isolation had been realized up to end of 1999, either because of high risk or expense. Also, the best producing oil well, 7-01 had indicated CO_2 response from the toe of 7C11H, and it was deemed too risky and expensive at that time to risk losing this oil productivity A workover was performed in July 2001 to reduce the injection losses in the toe of the well.

During December 1998 low crude prices dictated a cut back of CO_2 purchases to the lease. Overall CO_2 injection was therefore reduced from 7.9 MMSCF/D to 4.7 MMSCF/D in December 1998.

Appendix D

During the redevelopment period of November 2000 through March 2001, CO_2 injection was reduced while new laterals were drilled.

Following completion of all the Phase 1, Phase 2A and Phase 2B horizontal wells, CO_2 injection reached 7,972 MCFD in June 2001. As shown in the table below, Well 227W has failed to inject CO_2 due to poor permeability and high reservoir pressure. Well, 6-27 W injected at rates up to 1,500 MCFD, but by October 2001 high reservoir pressure resulted in injection falling to zero rate. All CO_2 injectors are still limited to a maximum wellhead injection pressure of 1,150 psig, as of June 30, 2002.

Over 74 percent (%) of all CO_2 injection has been into wells 6-25W and 7-11W, and 71% of current injection is into these two wells. Since the total unit gas production has not exceeded the production facility capacity, the CO_2 injectors have remained on almost continuous CO_2 injection, with very little water injection in each well. The table below summarizes the individual CO_2 well injection rates.

CO_2 Injection History By Well

DATE	226W MCFD	227W MCFD	625W MCFD	626W MCFD	627W MCFD	628W MCFD	711W MCFD	Total MCFD	Unit Cumulative MMCF
7/1/1996	265	72	0	0	0	0	0	337	10
8/1/1996	1,306	5	1,571	0	0	0	44	2,926	101
9/1/1996	1,382	66	3,438	0	0	0	2,854	7,740	334
10/1/1996	1,198	149	3,268	0	0	0	3,216	7,831	576
11/1/1996	1,459	76	3,724	0	0	0	3,723	8,982	846
12/1/1996	1,266	89	3,781	0	0	0	3,787	8,923	1,122
1/1/1997	913	4	3,393	0	0	0	3,328	7,638	1,359
2/1/1997	998	54	3,614	0	0	0	3,572	8,238	1,590
3/1/1997	1,192	120	3,293	0	0	0	3,887	8,492	1,853
4/1/1997	1,263	153	3,670	0	0	0	3,119	8,205	2,099
5/1/1997	839	140	3,445	0	0	0	3,442	7,866	2,343
6/1/1997	1,027	652	3,570	0	0	859	3,573	9,681	2,633
7/1/1997	938	373	3,371	877	0	979	3,456	9,994	2,943
8/1/1997	538	371	2,883	971	0	562	2,932	8,257	3,199
9/1/1997	727	294	2,718	793	19	0	686	5,237	3,356
10/1/1997	1,003	415	3,749	896	999	0	3,000	10,062	3,668
11/1/1997	990	580	3,617	874	986	0	3,612	10,659	3,988
12/1/1997	528	202	2,362	441	482	0	1,858	5,873	4,170
DATE	**226W MCFD**	**227W MCFD**	**625W MCFD**	**626W MCFD**	**627W MCFD**	**628W MCFD**	**711W MCFD**	**Total MCFD**	**Unit Cumulative MMCF**

1/1/1998	327	1	1,481	397	136	0	1,259	3,601	4,282
2/1/1998	396	0	1,244	621	85	0	1,274	3,620	4,383
3/1/1998	352	0	1,126	631	33	0	1,327	3,469	4,491
4/1/1998	315	3	1,414	1,059	20	0	1,397	4,208	4,617
5/1/1998	173	1	2,735	466	1	0	2,685	6,061	4,805
6/1/1998	158	0	2,817	490	0	0	2,655	6,120	4,988
7/1/1998	532	338	3,958	409	22	0	1,973	7,232	5,212
8/1/1998	641	398	4,301	0	45	0	2,179	7,564	5,447
9/1/1998	720	528	4,344	0	80	0	2,272	7,944	5,685
10/1/1998	750	496	4,220	350	86	0	2,542	8,444	5,947
11/1/1998	1,218	0	4,249	581	134	0	2,808	8,990	6,217
12/1/1998	282	0	3,135	377	15	0	1,852	5,661	6,392
1/1/1999	125	0	3,125	205	1	0	1,788	5,244	6,555
2/1/1999	119	0	3,203	209	5	0	1,846	5,382	6,705
3/1/1999	414	255	3,168	209	23	0	1,392	5,461	6,875
4/1/1999	461	131	3,034	212	23	0	1,279	5,140	7,029
5/1/1999	229	2	2,995	226	22	0	1,220	4,694	7,174
6/1/1999	14	41	3,678	0	0	0	1,282	5,015	7,325
7/1/1999	172	101	3,995	260	16	0	1,177	5,721	7,502
8/1/1999	648	190	3,992	556	37	0	551	5,974	7,687
9/1/1999	378	35	2,712	529	1	0	1,225	4,880	7,834
10/1/1999	361	5	3,141	541	2	0	1,355	5,405	8,001
11/1/1999	360	0	2,935	258	0	0	1,218	4,771	8,144
12/1/1999	282	0	2,986	0	2	0	1,470	4,740	8,291

	226W	**227W**	**625W**	**626W**	**627W**	**628W**	**711W**	**Total**	**Unit Cumulative**
DATE	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MMCF**
1/1/2000	311	*	2,990	0	0	0	1,436	4,737	8,438
2/1/2000	755	109	2,365	0	67	0	980	4,276	8,562
3/1/2000	1,874	336	0	0	168	0	0	2,378	8,636
4/1/2000	877	212	0	696	263	0	0	2,048	8,697
5/1/2000	562	179	1,031	1,321	118	0	978	4,189	8,827
6/1/2000	1,448	290	3,410	0	0	0	3,289	8,437	9,080
7/1/2000	1,275	267	4,071	0	0	0	3,205	8,818	9,354
8/1/2000	1,018	82	2,876	0	0	0	2,941	6,917	9,568
9/1/2000	1,511	0	2,393	0	0	0	2,225	6,129	9,752
10/1/2000	111	0	3,715	0	0	0	3,305	7,131	9,973
11/1/2000	0	0	2,514	0	0	0	2,454	4,968	10,122
12/1/2000	0	0	2,316	0	0	0	2,024	4,340	10,257

									Unit
Well	**226W**	**227W**	**625W**	**626W**	**627W**	**628W**	**711W**	**Total**	**Cumulative**
DATE	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MCFD**	**MMCF**

1/1/2001	0	0	1,827	0	0	0	3,786	5,613	10,431
2/1/2001	0	0	1,635	1,748	1,589	391	876	6,239	10,605
3/1/2001	0	0	1,833	1,474	1,470	1,609	0	6,386	10,803
4/1/2001	1,242	0	1,932	1,554	1,550	1,488	0	7,766	11,036
5/1/2001	956	0	2,143	1,420	1,395	1,486	0	7,400	11,266
6/1/2001	1,040	0	2,721	1,582	1,196	1,433	0	7,972	11,505
7/1/2001	675	0	2,717	1,274	839	1,190	365	7,060	11,723
8/1/2001	496	0	2,428	1,140	523	1,132	1,622	7,341	11,951
9/1/2001	486	0	2,471	1,155	283	1,127	1,550	7,072	12,163
10/1/2001	609	0	2,421	291	1	1,057	1,760	6,139	12,354
11/1/2001	679	0	2,500	0	0	1,094	1,853	6,126	12,537
12/1/2001	660	0	2,555	0	0	0	1,694	4,909	12,690
1/1/2002	742	0	2,501	1,072	0	24	1,908	6,247	12,883
2/1/2002	645	0	2,536	200	0	528	1,822	5,731	13,044
3/1/2002	635	0	2,512	204	0	614	1,689	5,654	13,219
4/1/2002	438	0	2,853	211	0	505	1,766	5,773	13,392
5/1/2002	367	0	3,455	150	0	548	1,162	5,682	13,568
6/1/2002	514	0	2,678	211	0	931	1,450	5,784	13,742

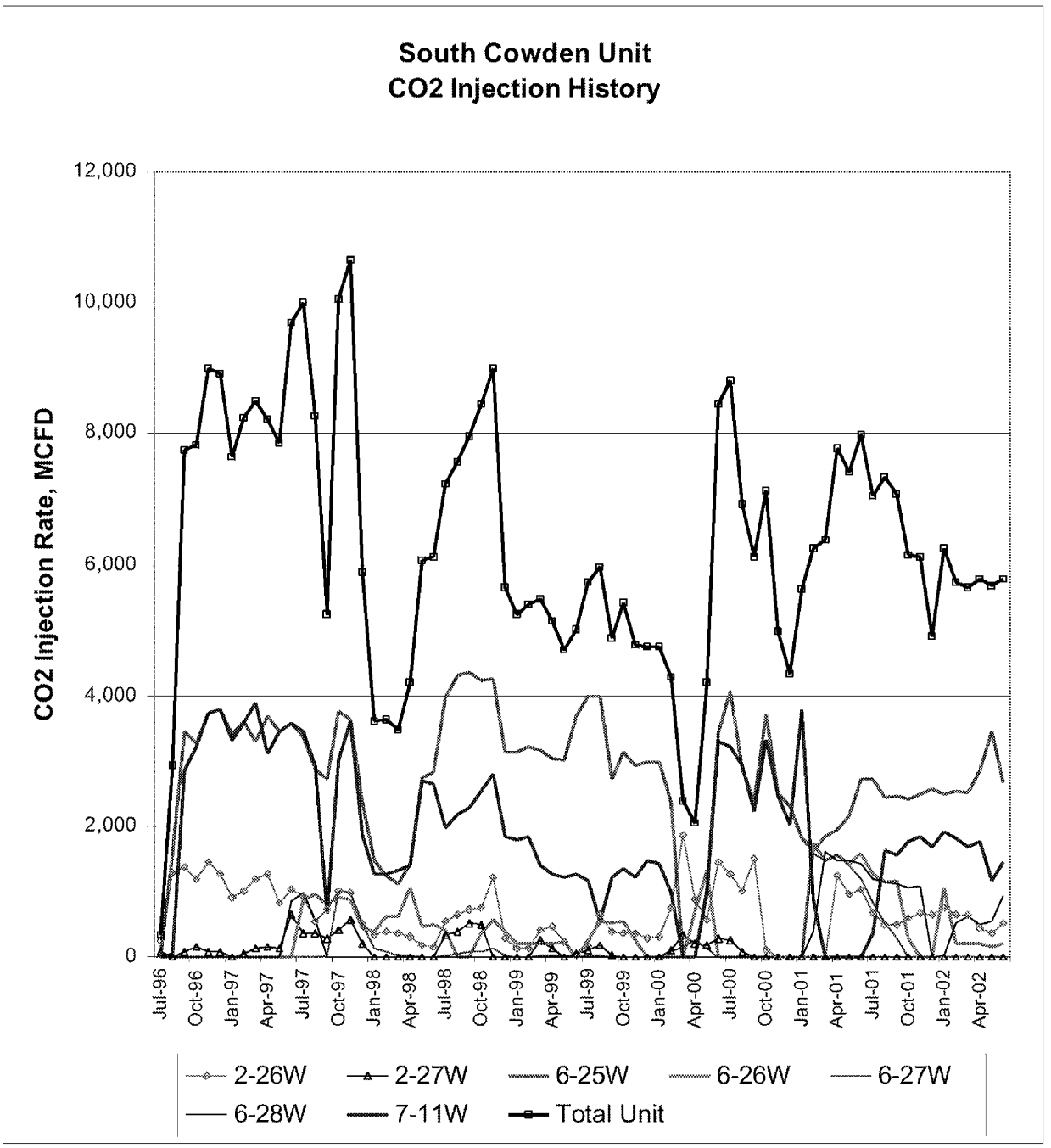
Cumulative injected by Well as of 6/30/02

	226W	**227W**	**625W**	**626W**	**627W**	**628W**	**711W**	**Total**
MMCF	1,436	239	6,116	885	385	534	4,147	13,742
% of Total	10.4%	1.7%	44.5%	6.4%	2.8%	3.9%	30.2%	

As shown in the table above, and in the graph below, nearly 75% of all injection has occurred in wells 6-25W and 7-11W, the two original horizontal injectors.

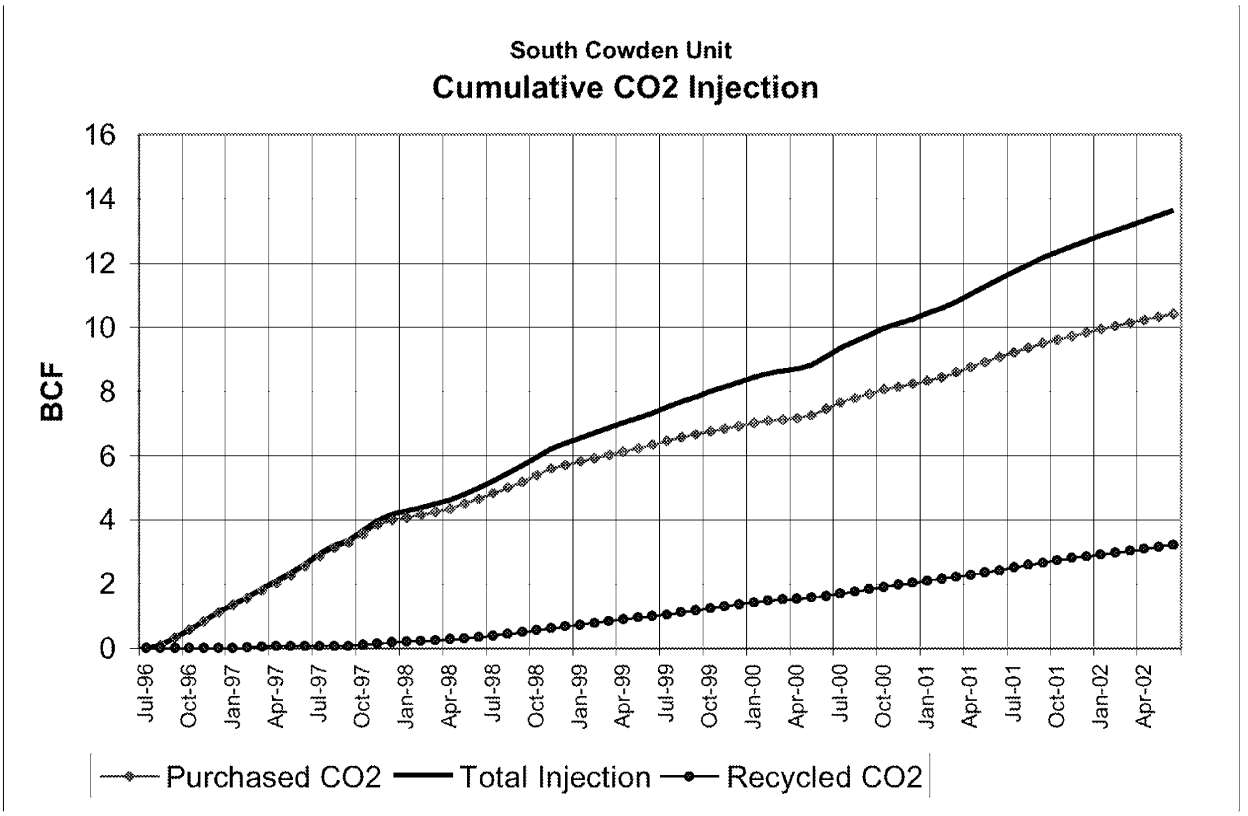
Appendix D

CO_2 Injection History By Well



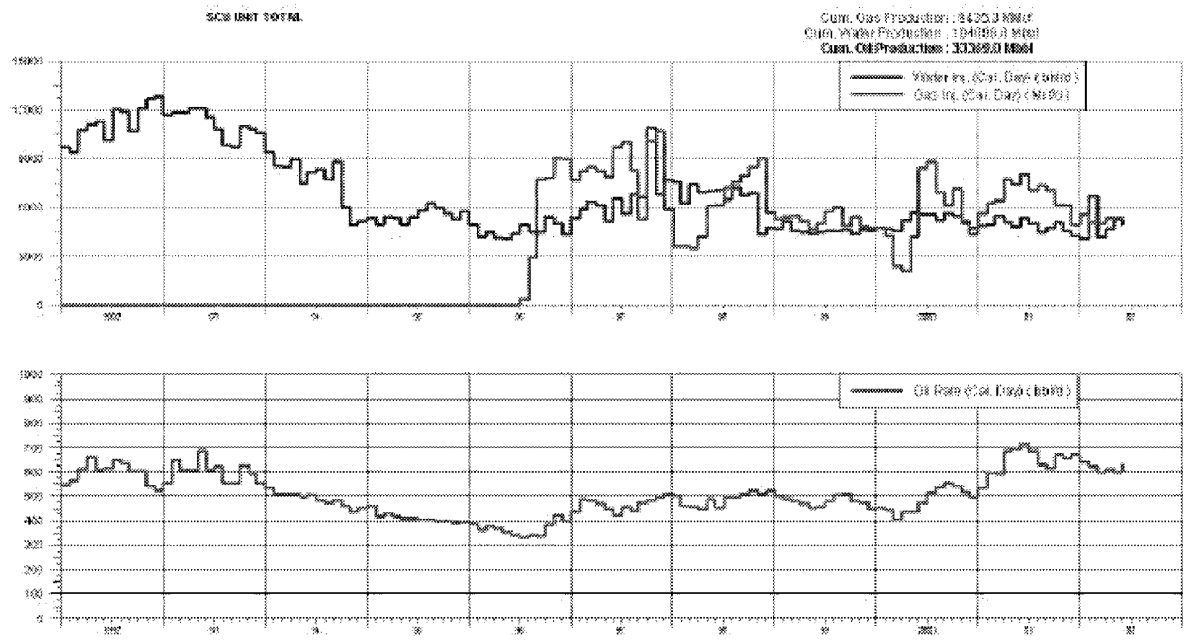
Appendix D

Cumulative CO2 Injection vs. Time



Appendix D

Water Injection, CO2 Injection, and Oil Production History, 1992-2002



Productivity Options Evaluated in 1999

After the poor success of the techniques tried in 1997 to 1998, the project team looked at alternatives for re-stimulation to improve productivity (also injectivity) without the use of stimulation above fracture pressures. It appeared the majority of stimulation methods, most noticeably acid stimulation, had not been effective at improving longterm offtake from San Andres upper layers. This is discussed in more detail in the Redevelopment Review in the attachments.

Alternative stimulation methods included:

a) Use of Halliburton's Stimtube/Stimgun/Powerperf technology followed by heated* matrix acid stimulation,
b) Lanced perforating, and
c) Use of short radius drilling.

* - Heated acid was thought to improve the upper layer stimulation, based on laboratory testing discussed below.

A candidate well No. 6-24 was initially identified to attempt to quantify re-stimulation techniques and their effect on injectivity/productivity. Due to the high pressures at the well, however, it would have proved too expensive to work on this well to attempt to use these technologies. Other wells were examined as alternative candidates.

Costs estimates were prepared for all these techniques including short radius drilling from existing wellbores. A service company from Houston was contacted to perform this particular estimate. These techniques were eventually used to assess the redevelopment options for SCU in year 2000, and are discussed in more detail in the redevelopment appendix.

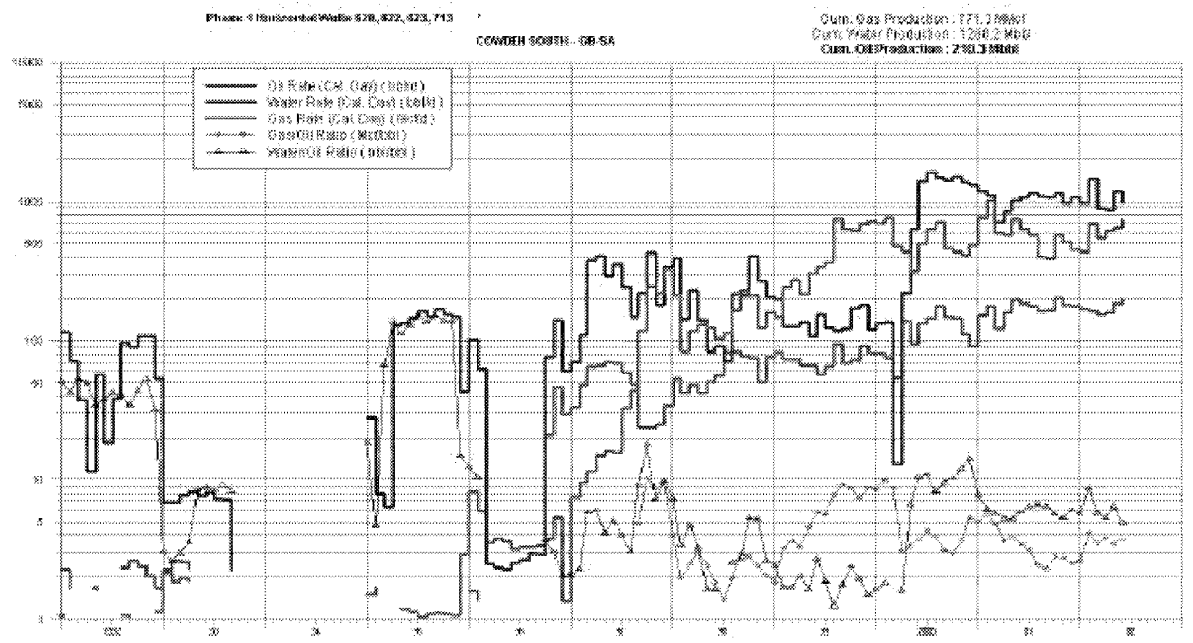
Production Response to CO_2 Injection

Phase 1 Horizontal Producers Production History

Horizontal producers drilled from existing vertical wells 6-20, 6-23, and 7-13 are north offsets to the highest-rate CO_2 injectors (6-25W and 7-11W), and well 6-22 is south of these two injectors. Because of the relatively high permeability in this area, and the large cumulative CO_2 injection in each of these CO_2 injectors, oil production response in these four wells has been good. The oil and water production rates increased significantly in mid-2000 with the completion of the horizontal laterals.

June 2002 production rate for the four wells totaled 198 BOPD, 747 MCFD, and 973 BWPD, which is nearly ten times the total reservoir barrel per day rate for these four wells in 1995 prior to the start of the CO_2 flood.

The graph below shows the oil, gas, water, gas-oil ratio, and water-oil ratio history for the four Phase 1 producers. The oil, gas, water rates, gas oil ratio (GOR), and water oil ratio (WOR) have been fairly steady for the past 18 months. These four producers offset the two original horizontal CO_2 injectors 6-25W and 7-11W.



Appendix D

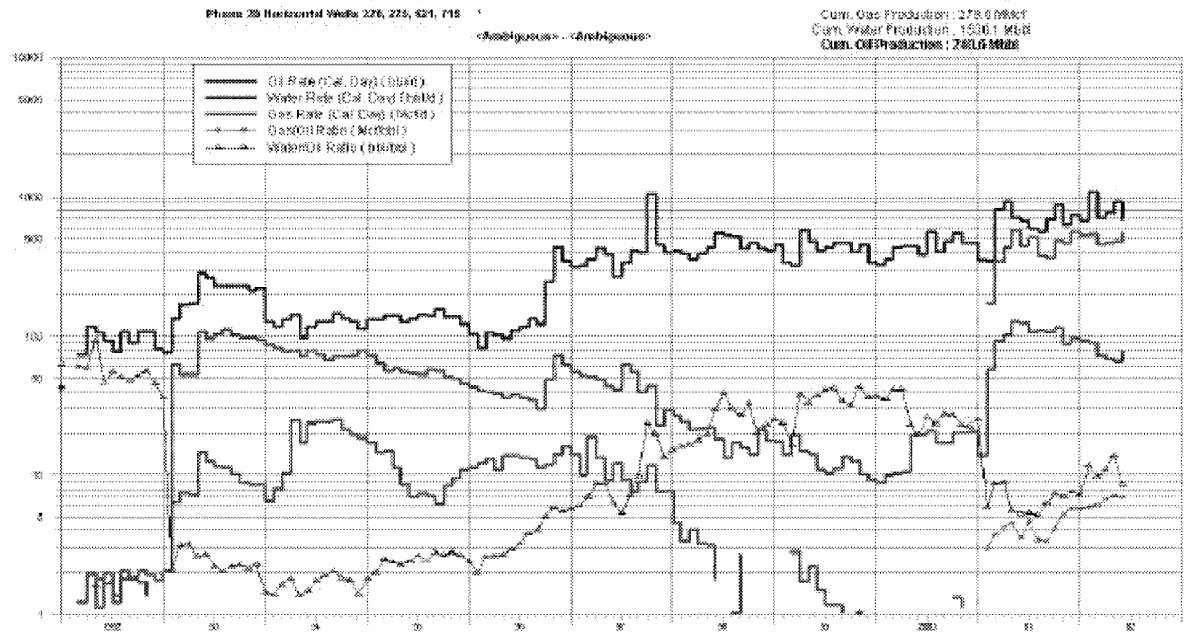
Phase 2B Horizontal Producers Production History

Phase 2A consisted of five horizontal injectors drilled from these existing producers: 2-26W, 2-27W, 6-26W, 6-27W, and 6-28W. Phase 2B consisted of horizontal lateral producers drilled from existing vertical wells 2-20, 2-25, 6-21 and 7-15.

Well 2-20 encountered very low permeability reservoir , and produces only 1 BOPD and 45 BWPD. Its direct offset CO_2 injector also penetrated very low permeability reservoir, and no CO_2 injection has occurred since August 2000.

Wells 2-25 and 7-15 offset Phase 2A CO_2 horizontal CO_2 injector 2-26W, and have responded well.

Well 6-21 is southeast of horizontal CO_2 injector 6-25W, has not performed as well as the earlier Phase 1 horizontal producers near this area. The graph below summarizes the production from these four Phase 2B producers. Oil production peaked in mid-2001, and is declining, while GOR and WOR are increasing.

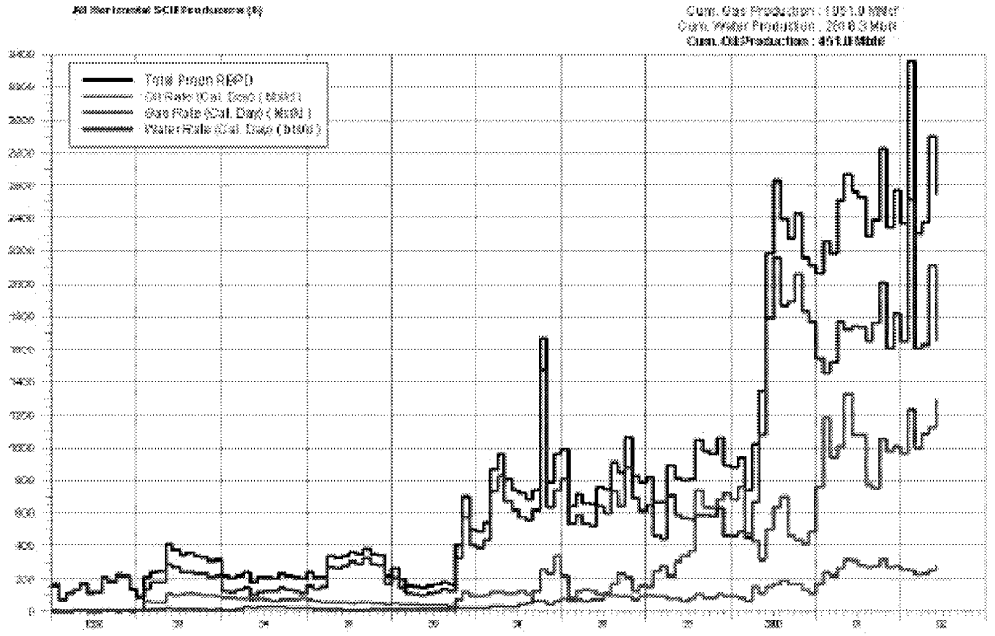


Phase 1 Plus Phase 2B Horizontal Wells

The graph of this group of eight wells illustrates the increased production rate resulting from completing horizontal producers. A primary goal of these wells was to lower reservoir pressure and allow faster "processing" of the reservoir in combination with the Phase 2A horizontal CO_2 injectors.

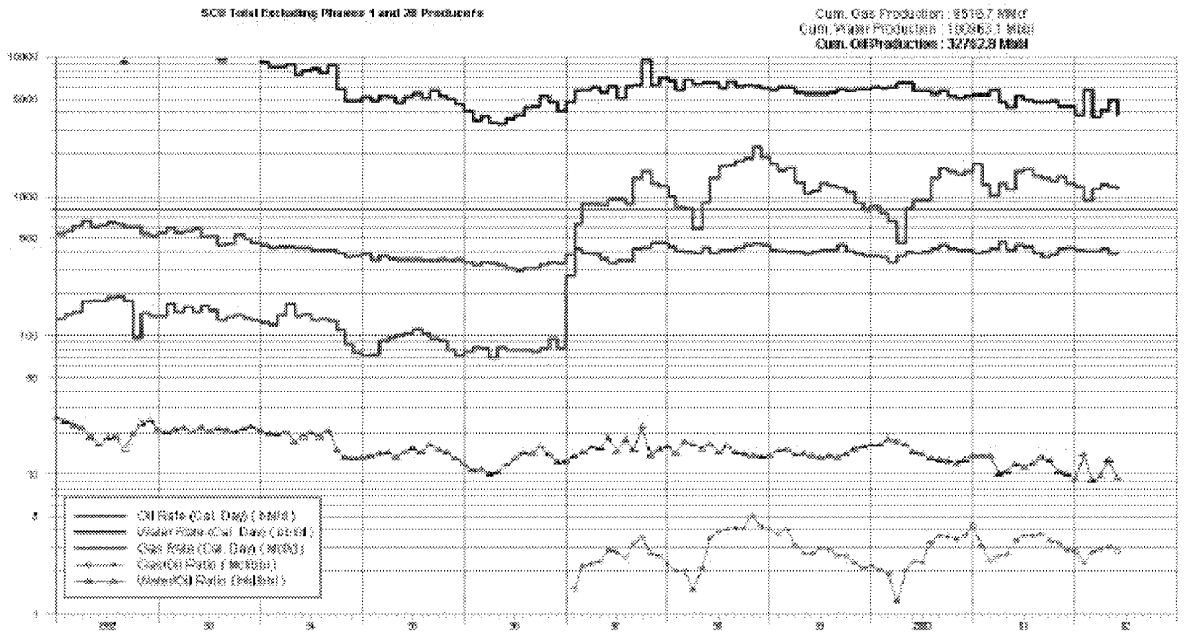
Appendix D

These eight horizontal wellswere drilled from existing wells during mid-2000 through April 2001. Total reservoir barrels per day production from these eight wells has increased ~1200%, from 200 BPD (vertical wellbores) to 2,400 BPD (horizontal). Oil production increased from 40 BOPDin August 1996 to 276 BOPD in June 2002.



Production from Vertical Wells

Unit oil production prior to CO_2 flooding was on a 16% per year decline, and would have reached the economic limit under waterflood (100 BOPD) by September 2003. Under CO_2 flood, the vertical wells in the South Cowden Unit have increased from a low of 300 BOPD in August 1996, to a steady 400 BOPD as of June 2002. Production from these wells is currently declining at one percent per year, and has produced within the range of 350 to 460 BOPD since late 1997. Water production and WOR are declining. Gas production is steady at 1,100 MCFD and GOR is also steady, at 3.0 MCF/BO. June 2002 production was 397 BOPD, 1,118 MCFD, and 3,779 BWPD.



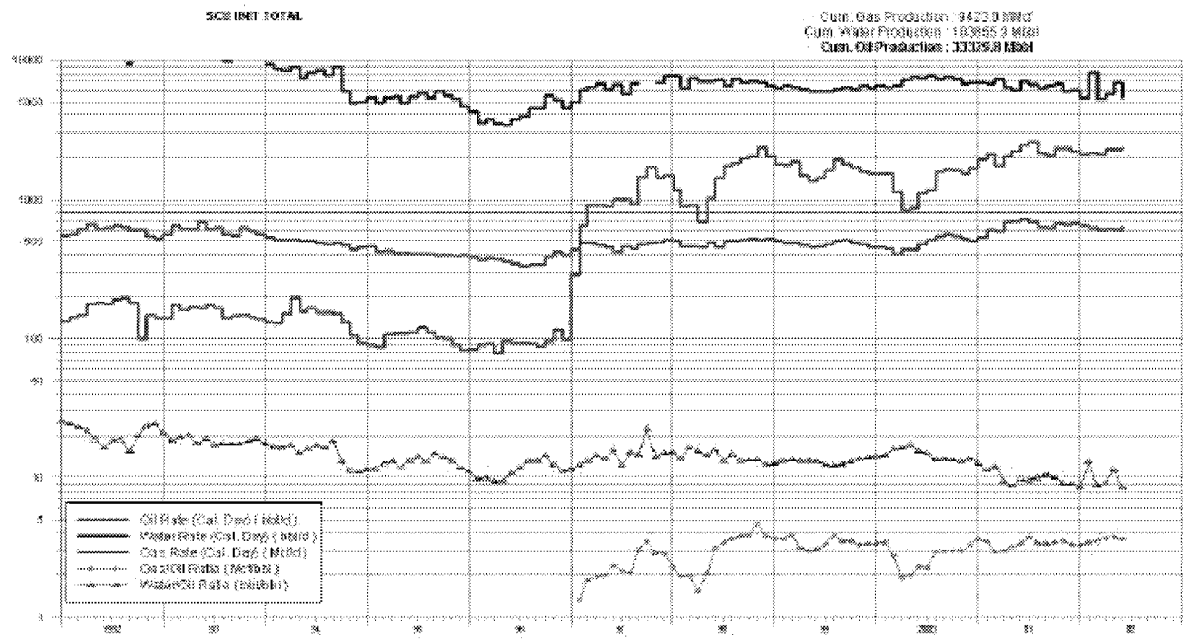
Unit Total Production

Unit production responded within months of first injection in 1996, and ranged between 400 and 500 BOPD until mid-2000. The production from horizontal wells completed in 2000 and 2001 resulted in a peak Unit production of 718 BOPD in June 2001. As of June 2002 UnitTotal production was 633 BOPD, 2,305 MCFD, and 5,371 BWPD. Water-oil ratio is at its lowest value since 1985. Gas-oil ratio is currently at 3,641 SCF/BO and is rising very slowly.

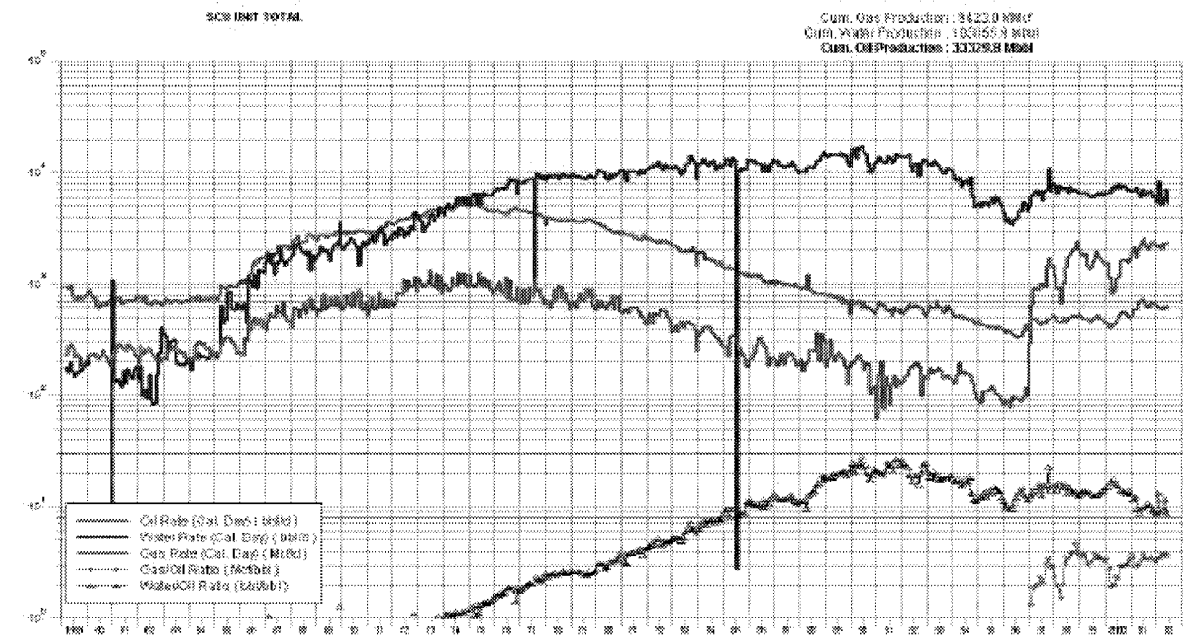
Cumulative gross CO_2 utilization is at ~ 21 MCF/BO and declining, as shown in the graph which follows. Instantaneous gross utilization is near 10 MCF/BO.

Appendix D

Unit Production History, 1992-2002, Log Scale

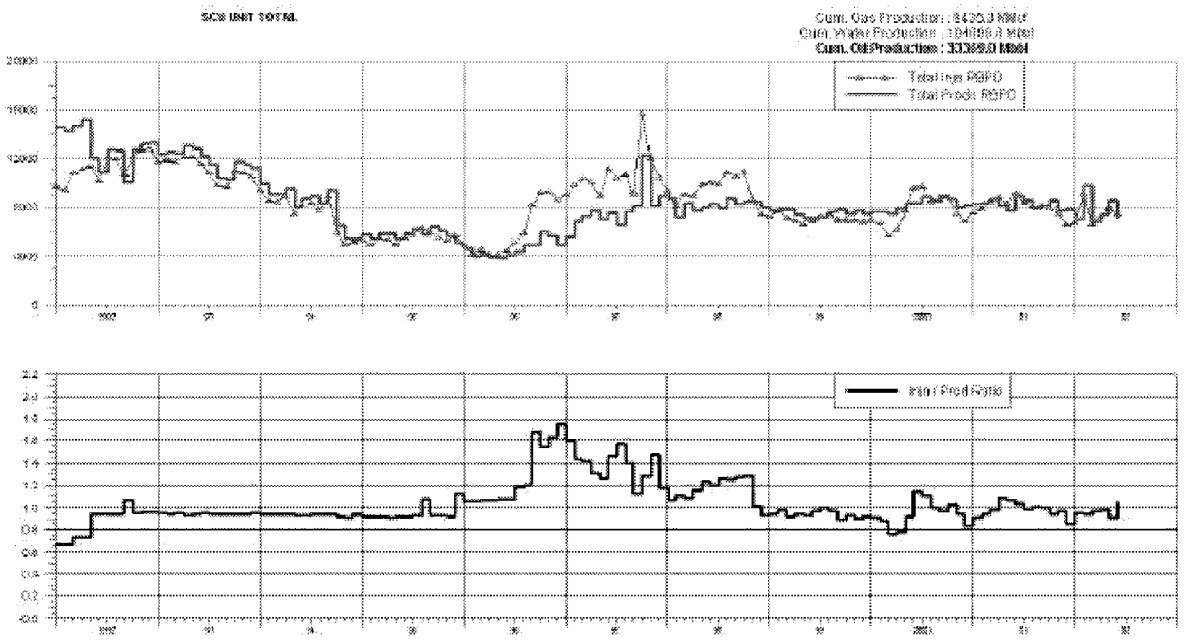


Unit Production History, 1959-2002



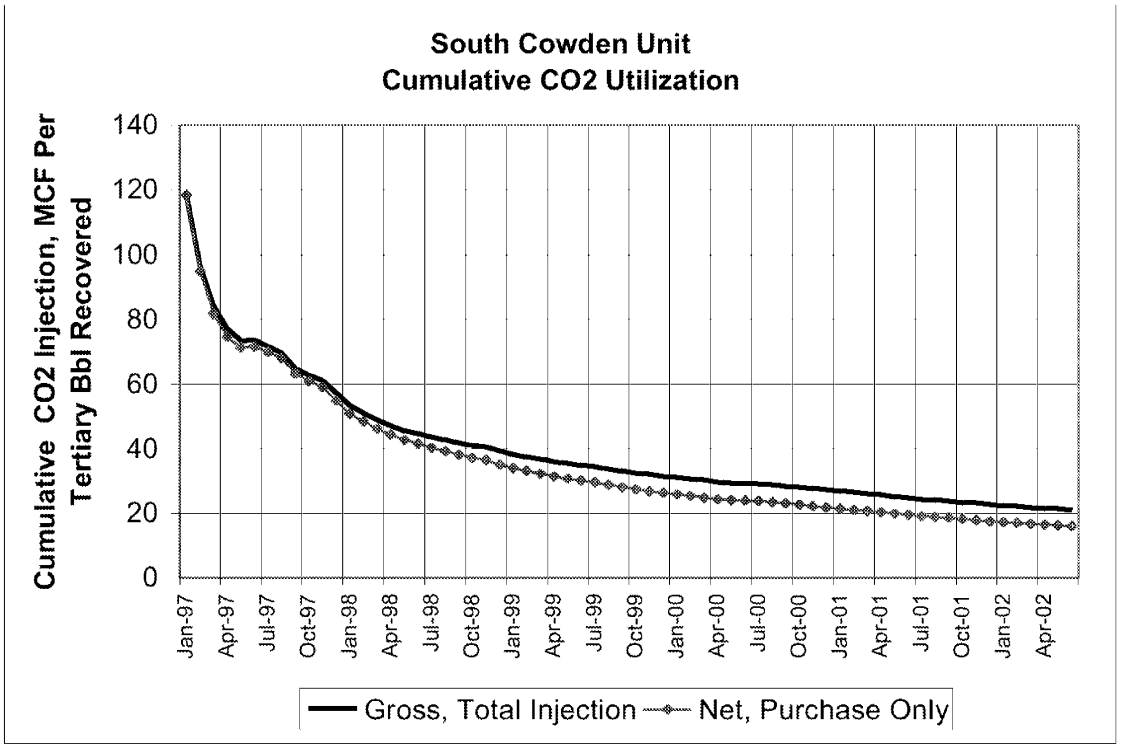
Appendix D

Unit Total Injection, Production, and Injection/Production Ratio, 1992-2002

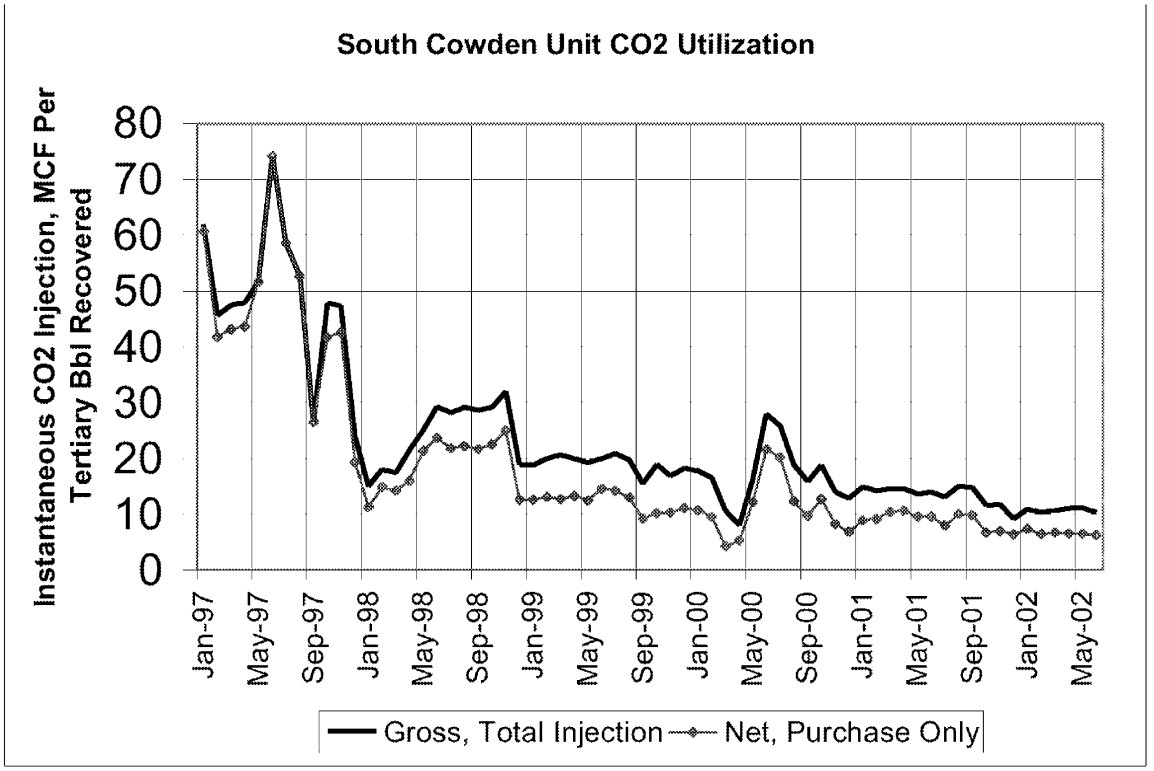


(Using constant CO2 FVF =2.1 MCF/RB)

CO_2 Utilization

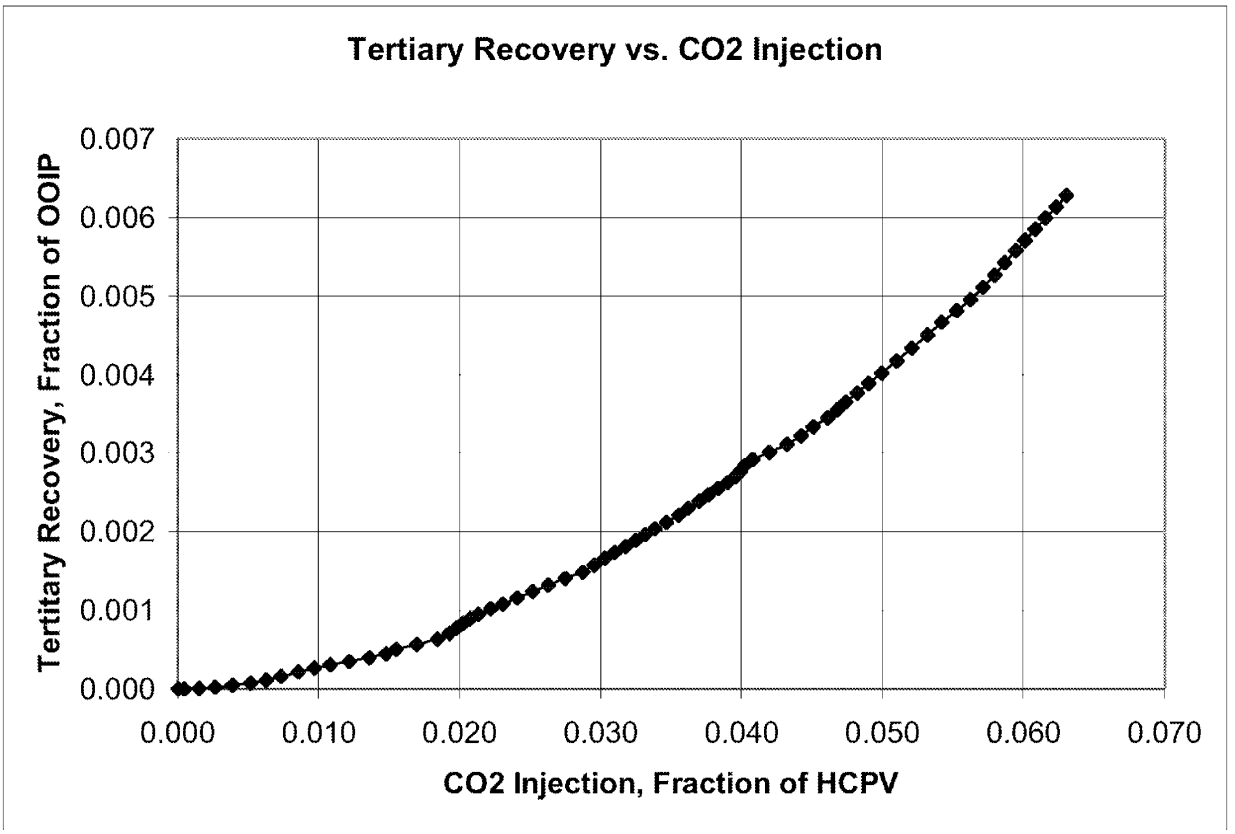


Appendix D


South Cowden Unit CO2 Utilization
Instantaneous CO2 Injection, MCF Per Tertiary Bbl Recovered
80
70
60
50
40
30
20
10
0
Jan-97
May-97
Sep-97
Jan-98
May-98
Sep-98
Jan-99
May-99
Sep-99
Jan-00
May-00
Sep-00
Jan-01
May-01
Sep-01
Jan-02
May-02
Gross, Total Injection
Net, Purchase Only

Appendix D

Tertiary Recovery vs. CO2 Injection



Appendix D

Oil Recovery Summary		MMSTBO	% OOIP
PROJECT AREA			
Estimated Original Oil in Place, Project Area	86.5		
Most Likely Estimated Ultimate Tertiary recovery (Assumes 6.0 % Decline rate to abandonment)		3.7	4.3
UNIT			
Estimated Original Oil in Place, Unit*		117	100
Estimated ultimate oil recovery, Primary + Secondary**		35.8	30.6
Cumulative recovery to 6/30/02		36.3	31.0
Cumulative Tertiary recovery to 6/30/02		0.6	0.5
Est. Ultimate Primary + Secondary + Tertiary		39.5	33.8
Most Likely Estimated Ultimate Tertiary recovery (Assumes 6.0 % Decline rate to abandonment)		3.7	3.2
High Side Estimated Ultimate Tertiary recovery (Assumes 4.0 % Decline rate to abandonment)		4.5	3.8

** Cumulative Oil at 41-65 Unitization = 9.77 MMSTBO
Non-Phillips Cum at 41-65 = 3.0 MMSTBO

* September 1, 1995 Phillips Petroleum Justification and Premises Report, South Cowden CO_2 Project

APPENDIX E

South Cowden Fine Scale Modeling

Appendix E

Summary

The San Andres intervals were split into 7 layers (A, B, C, D, E, F and G) as part of the characterization exercise. The South Cowden Unit (SCU) full field model, historically usedfor estimating reserves and production predictions, models layers C through F. These are the San Andres "upper layers" in the majority of the field, where the majority of recovery and carbon dioxide (CO_2) response is expected. Any out of zone injection into "lower layers" is treated in the full field model as a percentage loss of total CO_2 injected at surface.

To improve understanding of the interaction behind pipe and near well communication has on overall recovery a simple section model was built containing San Andres intervals A through F.

The model contained four wells. An original producer, a well introduced as a water injector in later field life, and finally two new wells drilled to replace the original producer and injector (which were abandoned at the start of the CO_2 flood). The two new wells are completed as a CO_2 injector and a producer.

The modelling was initiated to answer two issues:

1) Are abandoned wells, left with poor conformance, going to detrimentally affect CO_2 recovery?
2) Under what circumstances is CO_2 recovery degraded due to poor conformance in newly drilled wells?

The answers to which were found to be:

1) There appeared to be little effect on CO_2 recovery on older wells with behind pipe communication, *if* CO_2 processing could be maintained in upper layers with the newly drilled production wells. If CO_2 processing can be maintained in upper layers, *it is not recommended to re-enter existing abandoned wells to seal up the "backflow" that may exist between the San Andres intervals.*

2) It was determined CO_2 recovery *would* be effected if CO_2 processing and throughput in the upper layers could not be maintained with the newly drilled wells. In particular the *newly drilled production wells* must have good integrity to maintain offtake in upper layers. Offtake in lower layers was observed to induce CO_2 processing into the lower layers. The modelling assumptions to obtain this effect, however, assume relative permeabilities applied in the upper layers are also applicable in the 'C' zone, where a low permeability interval is thought to form a flow barrier.

As part of Phase 1 and 2 redevelopment activities, radioactive tracer and temperature injectivity surveys were performed in existing vertical producing wells. The 'level' of communication between the upper and lower layers is somewhat difficult to interpret precisely, but could be categorized broadly as small to severe. Only one well was interpreted as having severe communication. The injection log analysis revealed 30 percent (%) of wells had no communication issue, 14% had a small level of communication, 42% moderate levels and 14% severe communication. As South Cowden wells have similar completion histories this would

suggest 1 in 7 production wells might have a severe communication issue,requiring conformance techniques to prevent severe lower zone offtake.

Screening of well offtake rates, to identify unusually high historical liquid production rates, and further screening by comparison with simulation model rate predictions identified two candidates having the highest likelihood of communication issues. It is recommended to perform injection logs on these two wells, 6-19 and 7-05, to determine if conformance techniques should be applied.

The model sensitivities indicated the San Andresmight not have an effective isolation zone at the top of the C zone. Previous characterization work suggested this interval would form an isolation barrier to prevent fluid movement between zones D through F and the layers below the C zone.

Simulation modelling using the core data from 8-19 indicates the top of C zone has a finite permeability that does allow fluid movement, if pressure differential exists between the upper and lower layers.

Pressure differentials could be initiated during the initial depletion phase when wells were perforated in upper layers, or could exist during waterflood or CO_2 flooding where production wells have been completed with communication paths to lower layers. The offtake induces pressure drawdown in lower layers, and encourages injectant movement from upper to lower layers over the areal extent of the model.

Thus, if injectant is placed in upper layers, it is important offtake is encouraged only in upper layers with little or no communication issues allowed from lower layers.

Simulation of production wells having poor conformance, either during depletion or waterflood recovery phases, may help in explaining poorer recoveries during these primary and secondary phases. As with tertiary injection if communication to lower layers was present communication through production wells reduces overall recovery.

Note, however, the level of communication between upper and lower layers throughout the various wells at SCU is fairly uncertain. Also, that the modelling uses relative permeability curves derived from core flooding of cores taken from the main floodable zones. No relative permeability curves were derived from the tighter zones in the upper C zone.

Description of Model

The majority of model properties were taken from a Sensor compositional model originally built as part of the characterization exercise. The model was used to compare black oil simulation methods against Sensor fully compositional predictions.

The original model was altered to contain all seven San Andres layers. Layer properties of porosity and permeability were assigned based on average properties determined from South Cowden well 8-19 core data, illustrated in figures below. Porosity and permeability values were averaged using standard thickness weighted averaging techniques.

Appendix E

A pseudo temperature of 130 degrees Fahrenheit (F) was used to prevent Sensor from modelling 4-phase flow. Actual SCU reservoir temperature is 98 degrees F. An oil-water contact is placed in the model at the top of the B zone.

The section model was designed to simulate typical communication problems that may exist at South Cowden. The area between 6-28W, vertical CO_2 injector, and 6-01, vertical producer, was picked as a representative area. There are four wells in this area

7-07W	(vertical water injector – now abandoned),
6-28W	(vertical CO2 injector – drilled to replace 7-07),
6-01	(vertical producer – now abandoned) and
6-29	(vertical producer – drilled to replace 6-01).

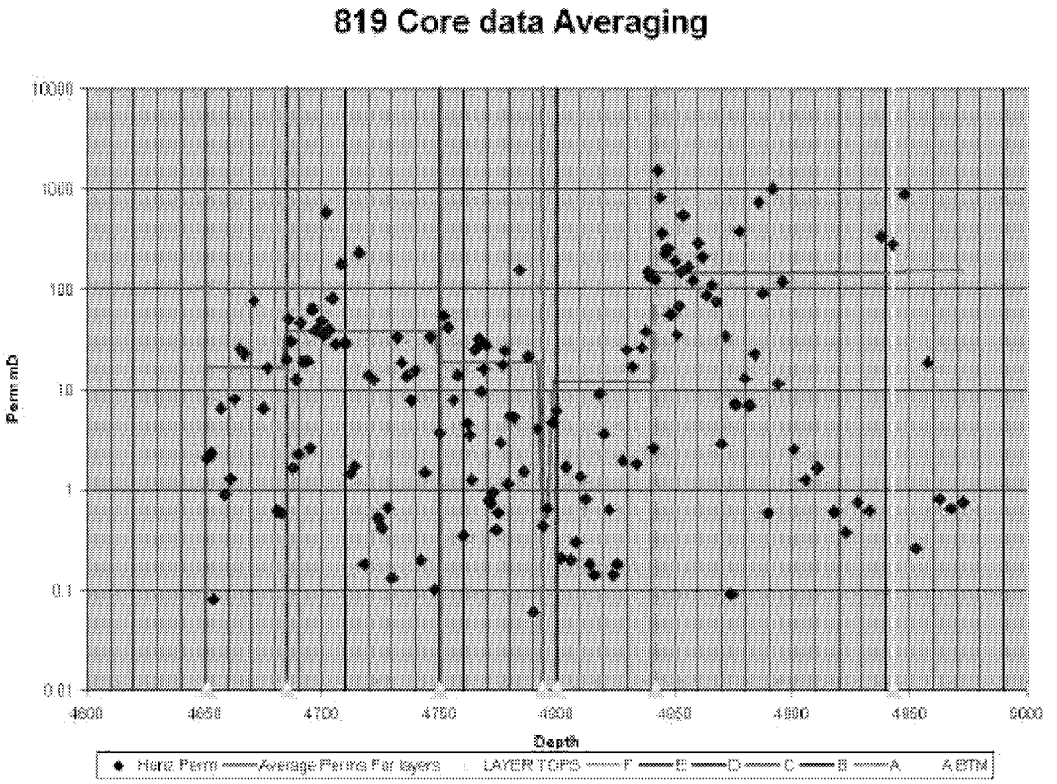
Some of these wells are known to have communication problems. The model is not being used for detailed history matching in this area. It is an illustrative model used to qualitatively analyse the effects of back flow through plug and abandoned (P&A'd) wells. The wells are therefore merely representative of the typical communication issues that may exist in the field.

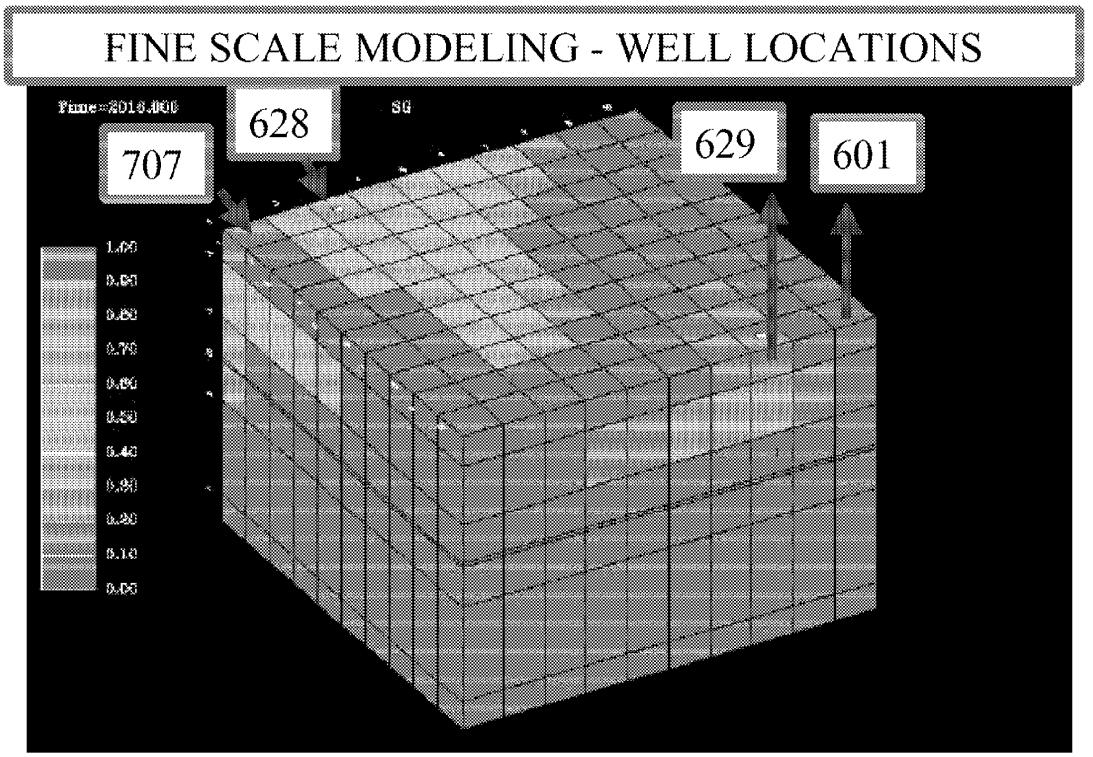
Communication paths through a well are modelled in Sensor by including all seven layers in the completion and allowing backflow by specifying rate as "zero". No communication paths are modelled by specifying rate as "–1". A printout of the model with well locations is illustrated below.

Appendix E

Summary New layering Scheme 819 core data
819 core data averaged into Main San Andres layers

Layer No	TopDepth	Zone	h ft	K mD	Kvert mD	Phi (frac)
1	4651.0	F	34.0	16.76	0.67	0.1591
2	4685.0	E	65.0	38.36	0.86	0.1445
3	4750.0	D	44.0	18.69	0.82	0.1367
4	4794.0	C	4.0	0.54	0.52	0.1336
5	4798.0	B	44.0	11.96	0.49	0.1202
6	4842.0	A	106.0	144.11	1.43	0.1273
7	4948.0	below	30.0	151.24	0.74	0.1272





Wells are produced at constant bottom hole pressure of 100 psi. Injection wells are constrained to inject at 2500-psi bottom hole pressure (BHP).

Appendix E

Cases Run and Results

A table summarizing model results is shown in the figure below. The model is set up to have a depletion phase, a waterflood phase, and a CO_2 injection phase. The phase duration is based on approximately matching saturations and pressures in the field at the end of each phase.

SOUTH COWDEN FINE SCALE MODELLING 2000

	Wells in Model				SIM NAME	OOIP	Oil Cum 8yrs		Oil Cum 14yrs			Oil Cum 22 yrs			Cum CO2 Inj	CO2 Efficiency
	601	707	628	629		MSTB	MSTB	% Rec	MSTB	% Rec	dof% Rec	MSTB	% Rec	dof% Rec	MMSCF	STB/MSCF During CO2 Sout
Type well	vert.prod	vert. IW	vert. CO2	vert. prod												
Start yrs	0	4	14	14												
End yrs	14	14	22	22												
Case 1	Upper 3	Upper 3	Upper 3	Upper 3	601_1.dat	1511	280.7	14	519.9	34	21	889.8	59	24	37574.1	9.8
Case 2	Upper 3	Upper 3	Upper 3	Upper 3	601_2.dat	1511	280.7	14	519.9	34	21	888.5	59	24	37459.8	9.8
Case 3	All 7(4-7s=1000)	Upper 3	Upper 3	Upper 3	601_3.dat	1511	281.1	13	494.9	33	21	863.6	57	24	36931.2	10.0
Case 4	All 7(4-7s=0)	Upper 3	Upper 3	Upper 3	601_4.dat	1511	94.5	6	225.5	15	8	595.4	39	24	33803.6	10.0
Case 5	All 7(4-7s=100)	Upper 3	Upper 3	Upper 3	601_5.dat	1511	162.0	11	404.8	24	13	731.8	48	24	35601.8	10.3
Case 6	Upper 3	All 7(4-7s=1000)	Upper 3	Upper 3	601_6.dat	1511	280.7	14	525.1	35	21	896.3	58	25	37455.1	9.6
Case 7	Upper 3	All 7(4-7s=0)	Upper 3	Upper 3	601_7.dat	1511	280.7	14	534.7	35	22	901.1	60	24	38108.4	10.1
Case 8	Upper 3	All 7(4-7s=100)	Upper 3	Upper 3	601_8.dat	1511	280.7	14	533.6	35	22	903.2	60	24	37749.5	9.9
Case 10	Upper 3	Upper 3	All 7(4-7s=1000)	Upper 3	601_10.dat	1511	280.7	14	519.9	34	21	888.1	59	24	36841.8	10.0
Case 11	Upper 3	Upper 3	All 7(4-7s=0)	Upper 3	601_11.dat	1511	280.7	14	519.9	34	21	882.4	58	24	28676.8	12.6
Case 12	Upper 3	Upper 3	All 7(4-7s=100)	Upper 3	601_12.dat	1511	280.7	14	519.9	34	21	874.1	58	23	31316.7	11.1
Case 13	Upper 3	Upper 3	Upper 3	All 7(4-7s=1000)	601_13.dat	1511	280.7	14	519.9	34	21	891.8	59	25	39659.2	8.4
Case 14	Upper 3	Upper 3	Upper 3	All 7(4-7s=0)	601_14.dat	1511	280.7	14	519.9	34	21	884.5	45	11	524783.3	1.3
Case 15	Upper 3	Upper 3	Upper 3	All 7(4-7s=100)	601_15.dat	1511	280.7	14	519.9	34	21	987.5	68	26	59327.9	6.5

Case1

DEPLETION PHASE: Wells 6-01 is drilled to the upper layers and produces for 4 years.

WATER INJECTION PHASE: Well 7-07 is then drilled to the upper layers. Water injection starts in well 7-07.

CO_2 INJECTION PHASE: After 14 years 7-07 and 6- 01 are shut in, and 6-28W and 6-29 drilled to the upper layers. CO_2 injection commences in 6-28, replacing injection from 7-07. Production starts in well 6-29, replacing 6-01.

Simulation stops at 22 years.

This case is used as an "ideal" case. All wells are drilled and completed in upper layers (1 through 3), waterflood and CO_2 flooding processing is in the upper layers only. Recoveries and CO_2 processing is therefore optimized and provides a "baseline" from which conformance sensitivities can be compared.

Case 1 represents a situation where old wells were abandoned correctly with a good cement squeeze to isolate all communication between layers. This prevents communication paths between layers prior to new wells being drilled at the start of CO_2 injection. Both injection and production from new wells takes place in zone, from upper layers.

Case 2

Case 1 is an ideal case where an old well has upper layer production from zones D, E and F. In reality old wells may have been nitro-glycerine shot and this*may* have opened up communication between all San Andres intervals. An old well may also have been stimulated above fracture pressure at some point during its history allowing communication between all layers Case 1 also assumed that when the well is plugged and abandoned (P&A'd) all zones are sealed up such that layers 1 to 3 do not allow back flow.

Case 2 is the same as case 1 in most respects. The difference is at 14 years where 7-07 and 6-01 are not sealed. They are left with communication between the upper layers, 1 through 3.

CO_2 injected in the upper layers at 6-28W is therefore capable of moving through the reservoir's upper layers to 7-07 where it may backflow through upper layers towards the producer 6-29. Similarly, upper layer fluid movement can migrate through 601 into upper layers to be produced at 6-29.

Case 2 represents the situation where old wells, with good conformance, are not abandoned correctly prior to new wells being drilled at thestart of CO_2 injection. In this particular sensitivity backflow is only allowed between the upper layers, so it is not surprising to discover profiles and recoveries are very similar to case 1, as there is no out of zone injection involved.

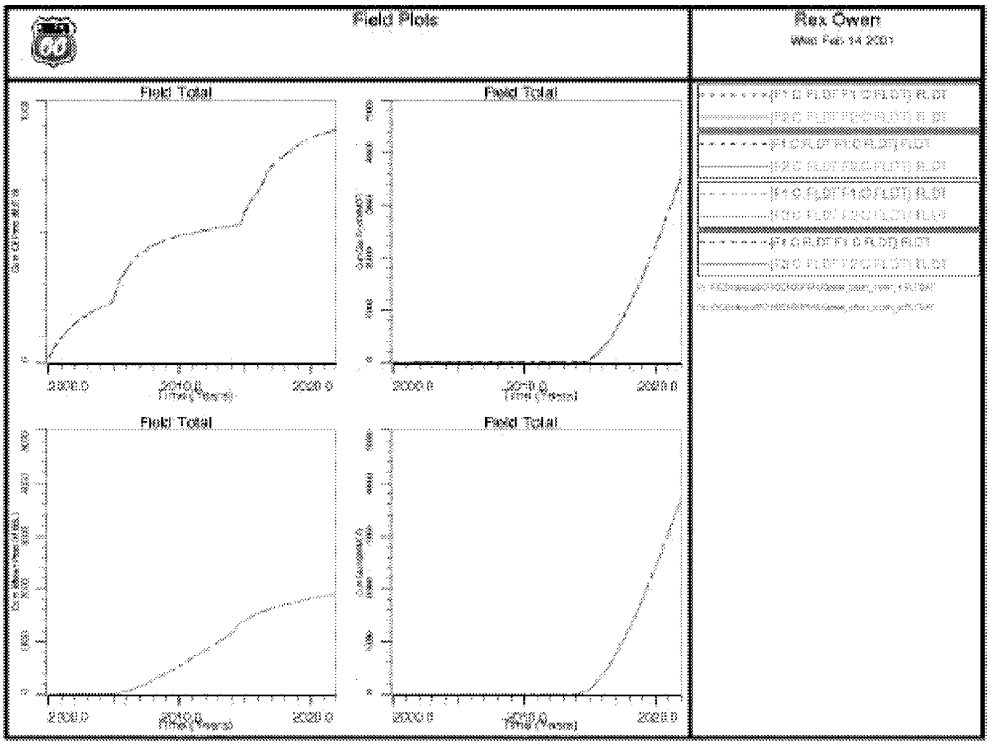
A comparison is drawn between case 1 (" F1" or 601_1.dat) and 2 ("F2" or 601_2.dat) in the figure below. As can be seen, there is little difference in oil recovery, CO_2 injection and production.

A few observations about these two runs.

1) During depletion *slight* coning tendencies are evident, illustrated in figure below. The cross section shows a view through XZ slice number 10 after 10 years. Well 6-01 is placed in cells (10,10, 1 through 3), as shown on the extreme right of the figure. The initial oil water contact (OWC) is placed at top B zone (layer 5).

The top of the C zone (layer 4) is characterized as an "impermeable boundary" hindering communication between zones.

SCU 8-19 core samples taken in the top C zone have finite permeability ranging between 0.4 and 0.6 millidarcies (mD). These samples, when viewed from core slab photographs, are in the tightest section of the C zone interval.

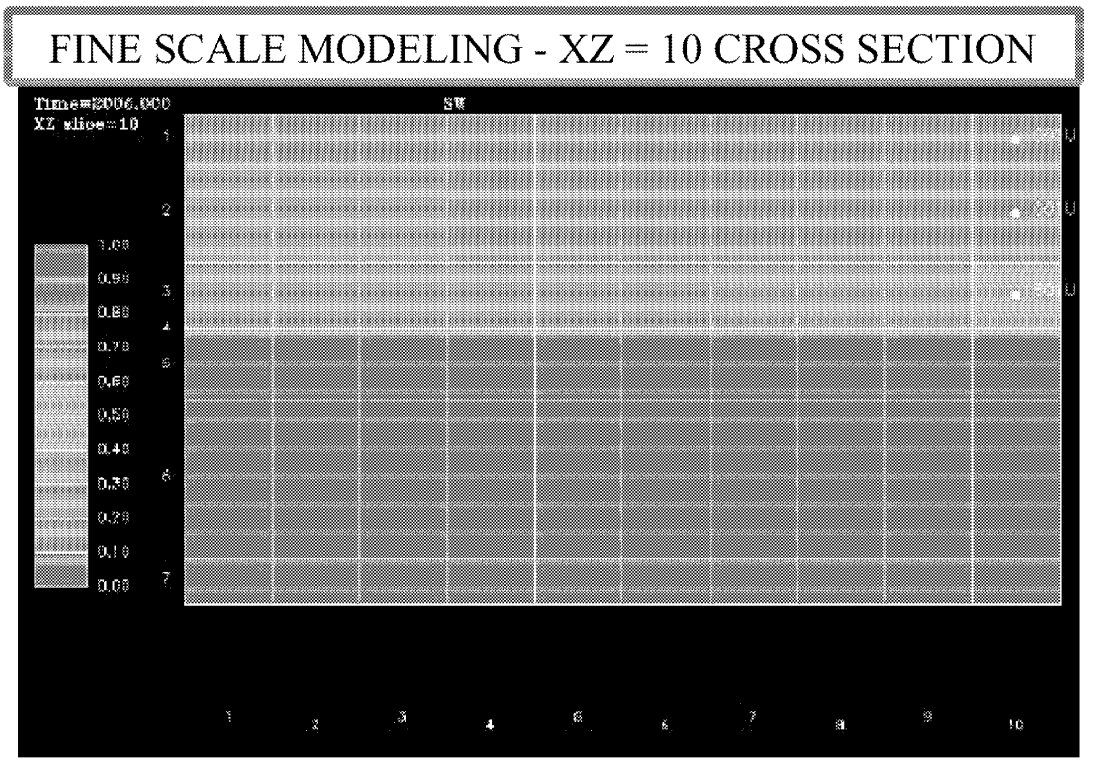


Yet using these smallest permeability it is evident a pressure distribution is present below the perforated interval, with resulting small coning behaviour in the near well area during the depletion phase.

2) Initial Oil in Place is 1,511 MSTB. After the depletion phase 208 MSTB was produced or 14% recovery. After the waterflood phase 519 MSTB was produced or 34% recovery. After the tertiary flooding 888 MSTB was produced, or 59% recovery.

3) At the end of CO_2 injection oil recovery is very similar for both cases.

4) Because wells are constrained at bottom hole pressures, there is no discrete volume control of CO_2 injected in both cases. For Case 1 and 2 total CO_2 injected is very similar at 37.5 BSCF.



Case 3

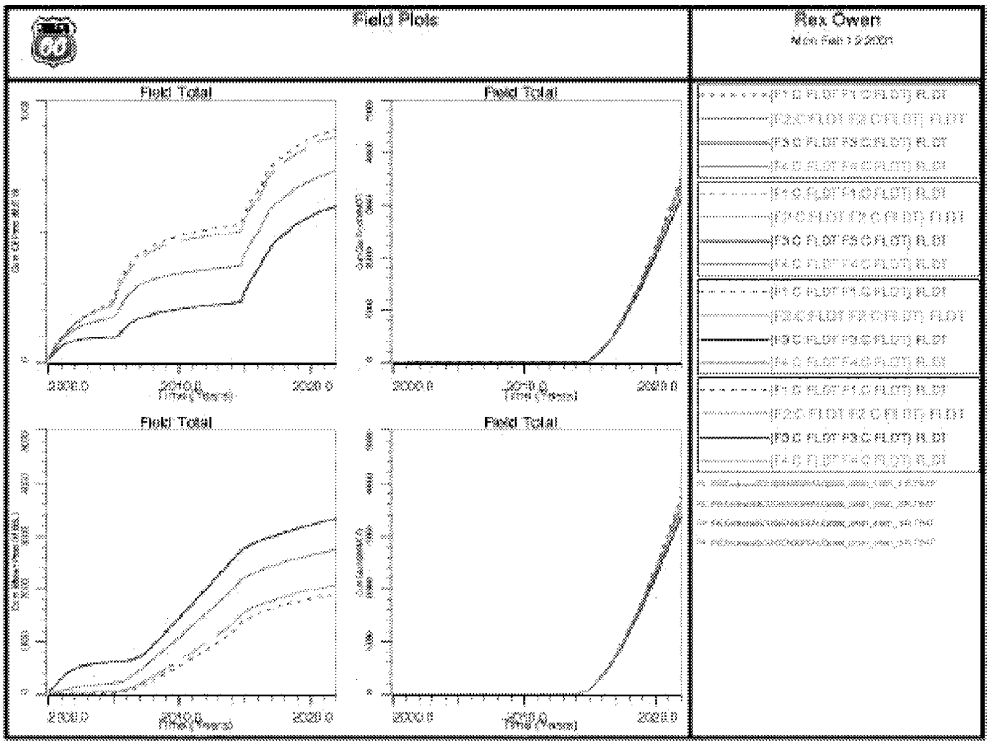
Case 3 is similar to case1. 601, however, is completed in all 7 layers. The assumption is 601 is nitro-shot during its initial completion, and is also not sealed up correctly when it is plugged and abandoned in year 14. The "level" of communication between upper/ lower layers is controlled by specifying skin factor for the lower layers, 4 through 7. In case 3 it is set to 1000.

Case 4

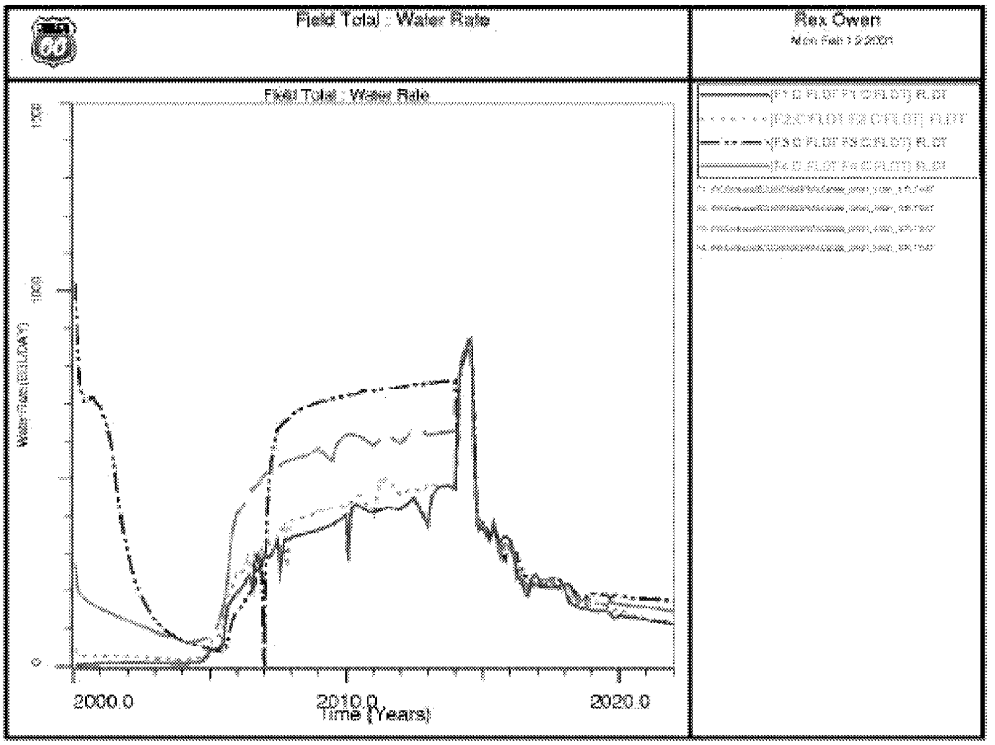
Case 4 is similar to case 3 but with a lower layer skin factor of zero. This represents the worst level of communication between the upper/lower layers.

Case 5

Case 5 is similar to case 3 but with a lower layer skin factor of 500.

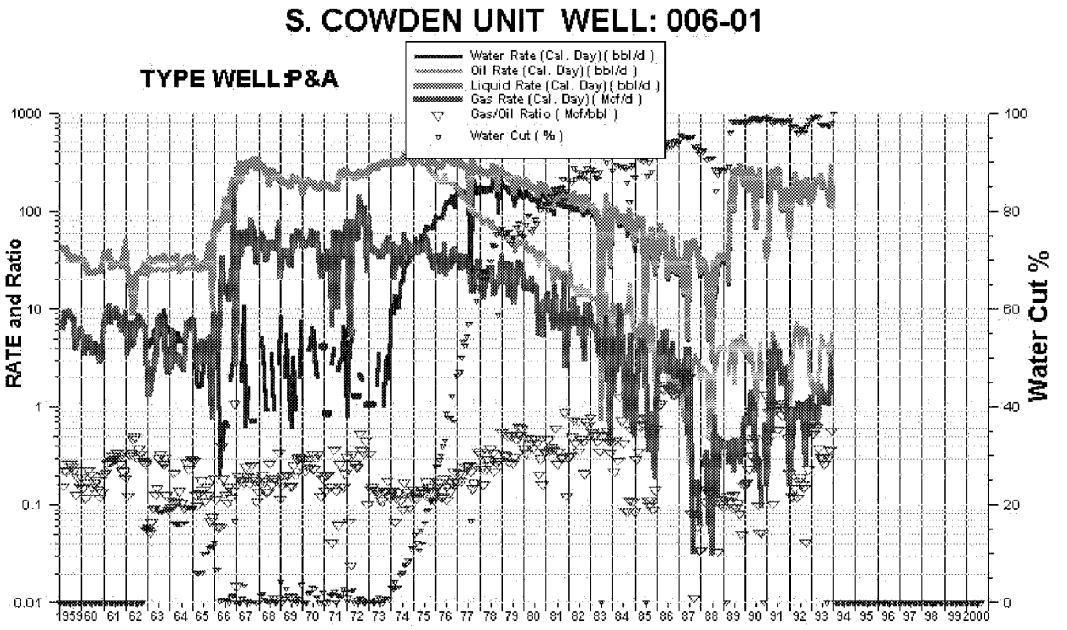


Cases 3 (F2 in the figure), 4 (F3) and 5 (F4) can be compared to illustrate how the level of upper to lower communication affects recovery and profiles from production wells, if it exists. More communication allows initial out of zone water production to dominate early production history, resulting in poor depletion and secondary recovery, illustrated below.



The "level" of communication is uncertain throughout SCU, but to "represent" the communication a skin of 100 could be used. Obviously a well may have poor near well communication and a skin of zero is more representative, or, conversely, has little or no communication. It will depend on a well-by-well basis, and only a detailed analysis of the well history will reveal whether an area in SCU has suffered from some of these concerns.

For example, actual data from 6-01 shows little water production from the 1950s until the start of the waterflood. It was only in 1974 when water production started increasing above 1 or 2 bw/d. This would suggest that little or no communication to lower layers existed



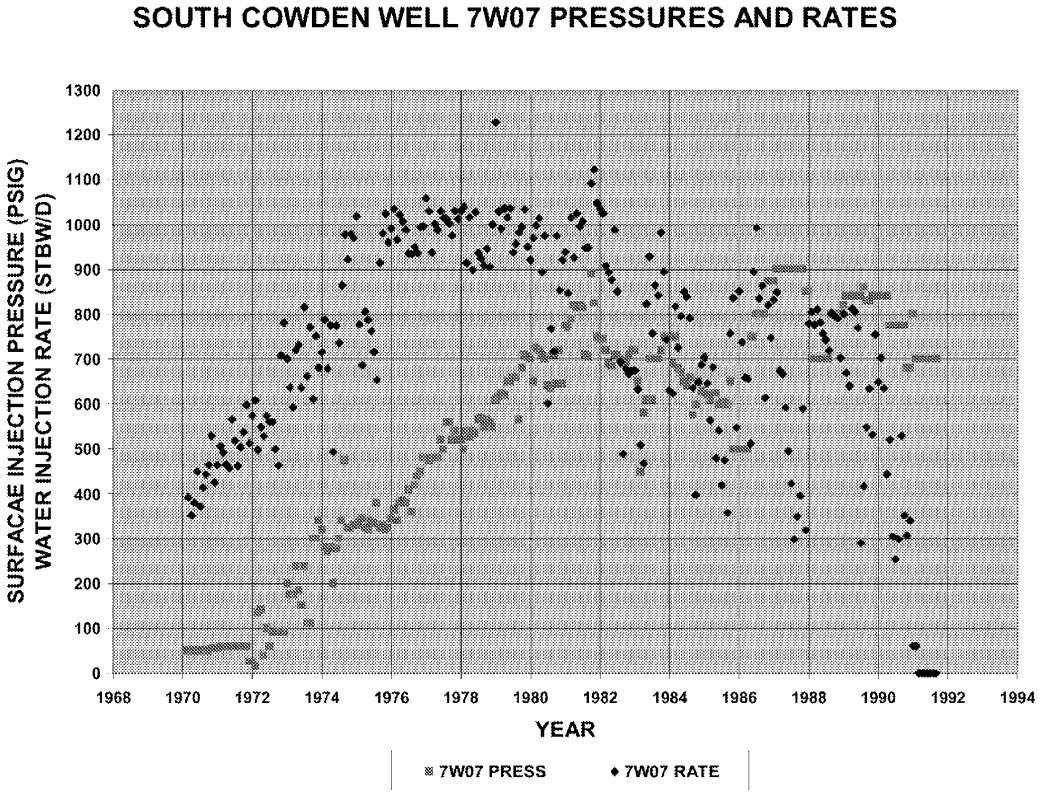
Of note are the incremental reserves associated with CO_2 injection, in all cases 3 through 5, no matter what the level of communication; there is consistently a 24% increase in recovery above the waterflood recovery.

Case 6

Case 6 is similar to case 1 but with 7-07 allowed to have communication between all 7 layers during the waterflood, and is not sealed when it is plugged and abandoned in year 14. Specifying skin factor for the lower layers controls the "level" of communication between upper/ lower layers. In case 6 it is set to 1000.

This is a case where all production wells produce from the upper layers, but during the water injection phase injection takes place with communication allowed to all layers. CO_2 injection is allowed to migrate between layers through an abandoned water injection well.

In reality SCU well 7-07 had very poor control of injection during its history, illustrated below. Historical surface injection pressures were allowed to increase to 800-900 psi at its abandonment. Near well communication paths were therefore highly probable through some of its history, being initiated when injection pressures exceeded fracture pressure.



Case 7

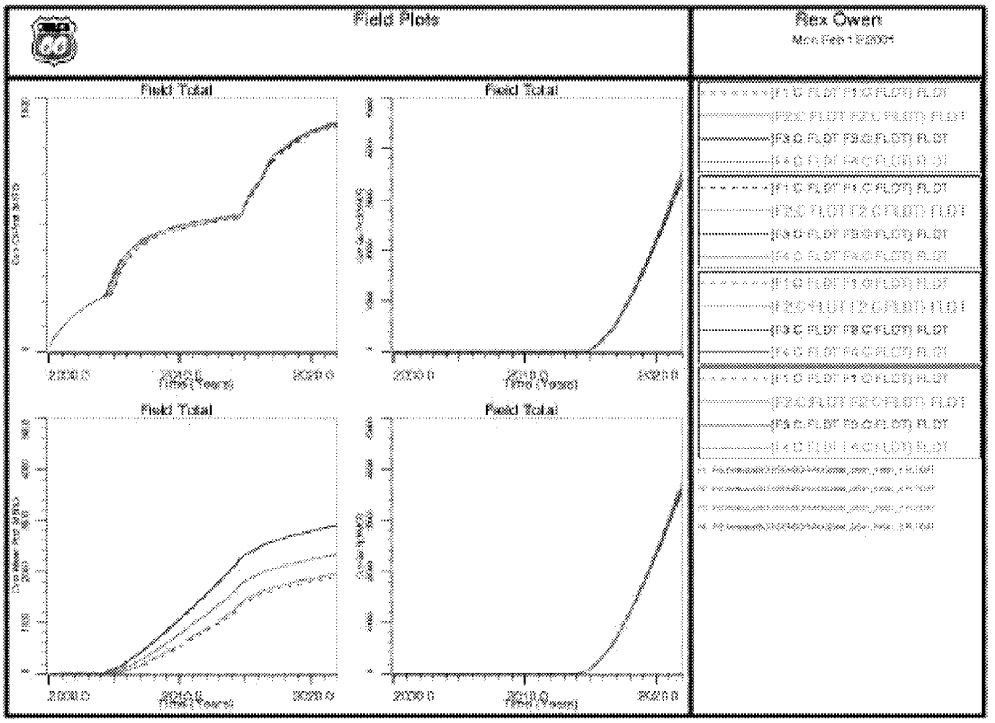
Case 7 is a sensitivity of case 6 with a skin of 0 applied in the lower layers to increase upper/lower layer communication.

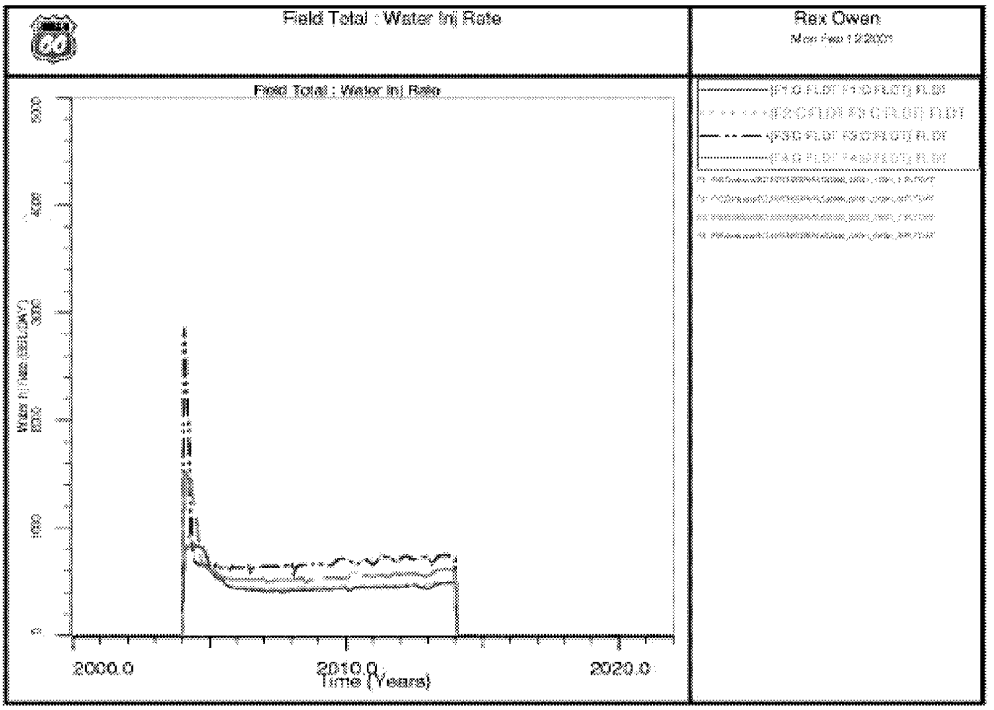
Case 8

Case 8 is sensitivity of case 6 with a skin of 100 applied in the lower layers to change upper/lower layer communication.

Cases 6 (F2 in the figure below), 7 (F3) and 8 (F4) benefit from increased injectivity in the reservoir, and as a result recover slightly more oil on waterflood when compared to the original case, where injectivity is constrained within the upper layers. Note there appears to be no overall loss in CO_2 phase recovery when communication is allowed through a poorly abandoned water injection well. CO_2 processing is constrained within the upper layers for both the CO_2 injection and production in the Wells 6-28W and 6-29 during CO_2 phase.

Appendix E


Field Plots
Rex Owen
Field Total
Field Total
Field Total
Field Total


Field Total : Water Inj Rate
Rex Owen
Field Total : Water Inj Rate
2000.0
2010.0
Time (Years)
2020.0

Consistently throughout cases 2 through 8 it is apparent if upper layer CO_2 processing is maintained, with injection and production wells completed only in layers 1 through 3, there is little difference to CO_2 recovery, on an incremental basis, compared to waterflood recovery, as illustrated in the summary table above.

Cases below investigate opening up communication paths in newer wells and the effect on CO_2 recovery.

Case 10

This case is similar to case 1, with upper layer processing during the depletion and waterflood periods. When CO_2 injection commences, existing wells are sealed, but CO_2 commences at 6-28W in all layers. This is to model near well communication effects in a newly drilled injector. Previous production and injection took place in zone. The 6-29 replacement well for 6-01 is completed only in upper layers. The level of communication in 6-28W is controlled with a skin factor of 1000.

Case 11

Case 11 is sensitivity of case 10 with a skin of zero applied in the lower layers to increase upper/lower layer communication.

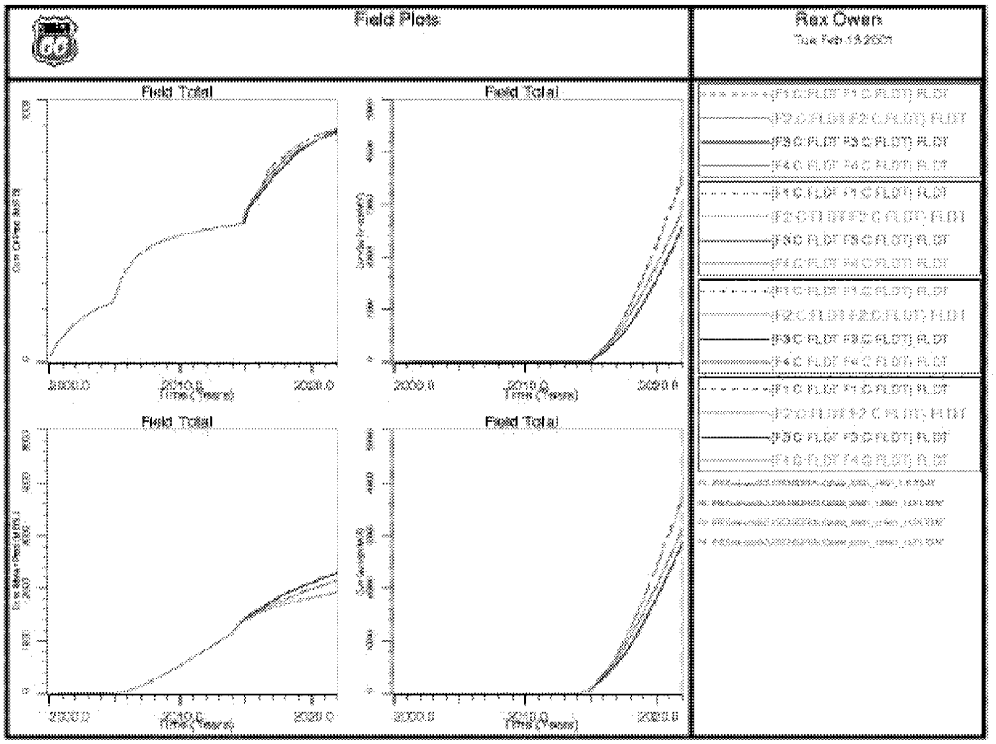
Case 12

Case 12 is sensitivity of case 10 with a skin of 100 applied in the lower layers to alter upper/lower layer communication.

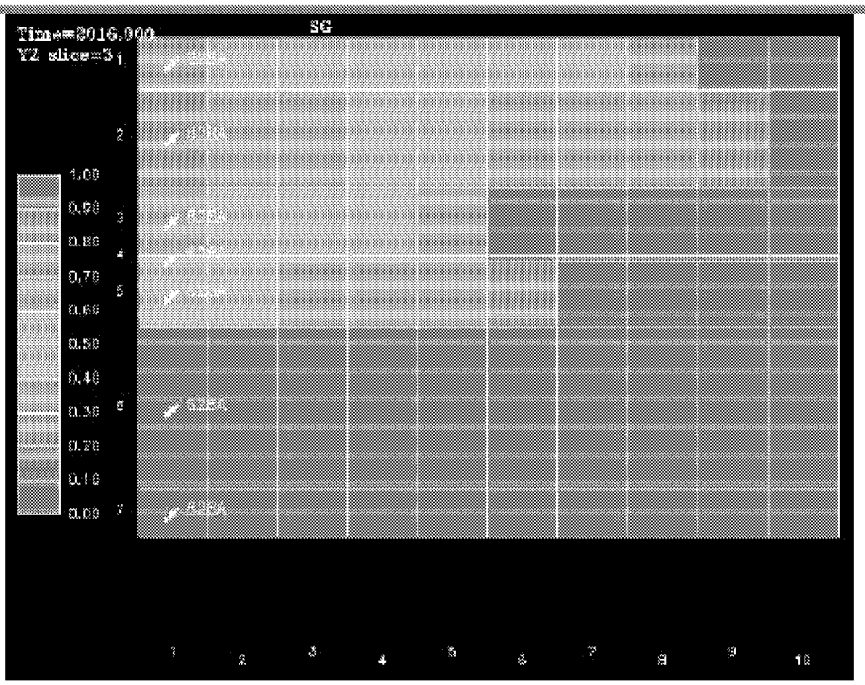
Note cases 10 (F2 in the figure), 11 (F3), and 12 (F4) suggest little or no loss in recovery for the CO_2 phase, somewhat counter-intuitively. It appears even though CO_2 injection is permitted out of zone in 6-28W, there is no recovery change from upper layer CO_2 processing. It appears when 6-29 has no offtake from lower layers CO_2 will not migrate through the lower layers.

The CO_2 saturation around 6-28W is illustrated below after 2 years CO_2 injection. CO_2 migrates only in the near well area around 6-28W and does not have significant penetration into the lower layers.

Appendix E



FINE SCALE MODELING - YZ = 3 CROSS SECTION



Case 13

This case is similar to case 1, with upper layer processing during the depletion and waterflood periods. When CO_2 injection commences the existing wells are sealed up, CO_2 commences in 6-28 in upper layers, but 6-29 is allowed communication between upper and lower layers. This is to model near well communication effects in a newly drilled producer. Previous production and injection took place in zone. The level of communication in 6-29 is controlled with a skin factor of 1000.

Case 14

This is similar to case 13, but with worse communication allowed at 6-29, using a skin of zero.

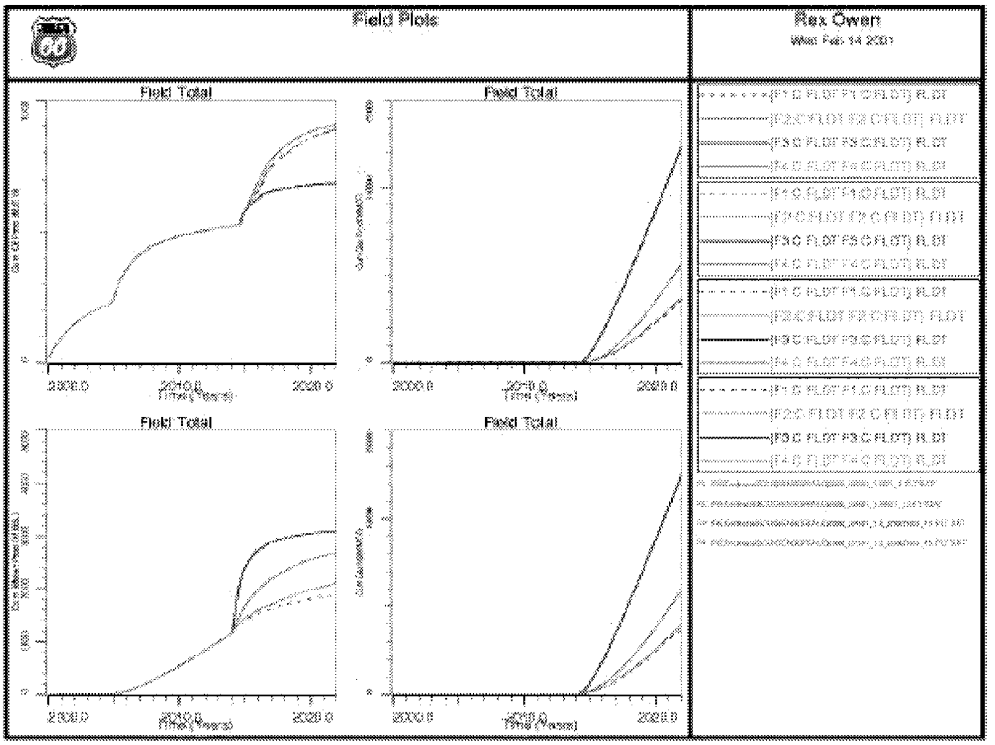
Case15

Case 15 is sensitivity of case 13 with a skin of 100 applied in the lower layers to alter upper/lower layer communication.

The figure below illustrates the differences between cases 13 (F2 in the figure), 14 (F3) and 15 (F4).

As with cases 3 through 5, when producing wells are completed with communication open to lower layers it appears to dramatically effect recovery and processing efficiency.

Note case 15 has similar percent CO_2 phase recovery increase of 26%, compared to the base case (case1). In order to recover the same oil reserve, however, requires 59 BSCF of CO_2 injection compared to 37 BSCF for the base case, a 58% increase. The CO_2 efficiency during the waterflood is therefore below average.



Conclusions Cases 3 though 15

Cases 3 through 15 illustrate the effect on CO_2 recovery when individual well conformance issues are considered. The largest impact appears to be for newly drilled producers. If conformance issues are present they tend to induce downward crossflow movement of injectant to lower layers. This behaviour will be induced for newly drilled wells or any well on production during the CO_2 phase.

This modelling behaviour will be realized in the field only if relative permeability measurements used are applicable for all San Andres intervals. If the lower permeability C zone has a tighter relative permeability characteristic then crossflow may not be as evident. The level of communication in production wells is also uncertain. Most were acid stimulated above fracture pressure. This is thought to have induced stimulation in the lower intervals, but may have re sealed over time.

As part of Phase 1 and 2 redevelopment activities, radioactive tracer and temperature injectivity surveys were performed in existing vertical producing wells. The 'level' of communication between the upper and lower layers is somewhat difficult to interpret precisely, but could be categorized broadly as small to severe. Only one well was interpreted as having severe communication. The injection log analysis revealed 30% of wells had no communication issue, 14% had a small level of communication, 42% moderate levels and 14% severe communication.

As South Cowden wells have similar completion histories this would suggest 1 in 7 production wells might have a severe communication issue, requiring conformance techniques to prevent severe lower zone offtake.

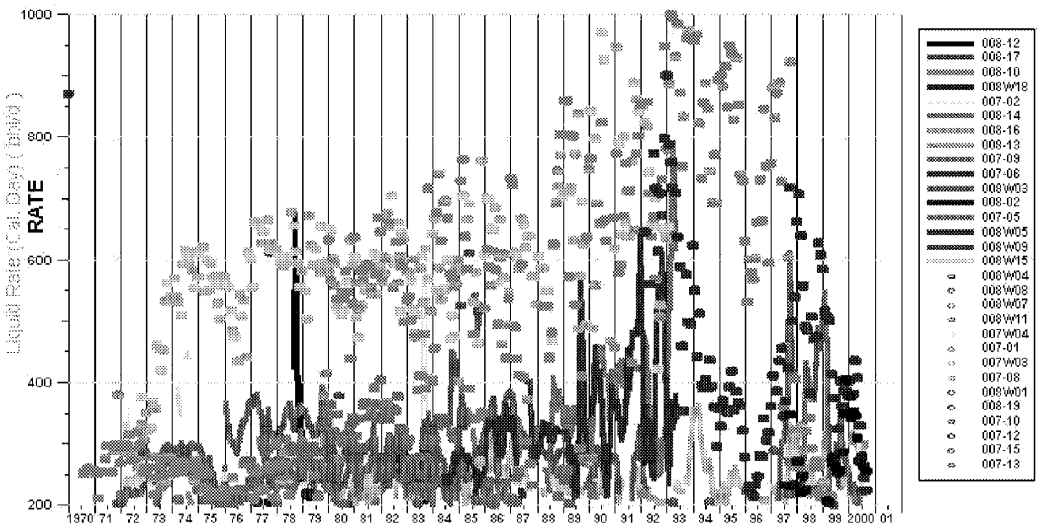
Screening criteria to identify high communication issues.

Screening of well offtake rates, to identify unusually high historical liquid production rates, and further screening by comparison with full field simulation model rate predictions can identify candidates having the highest likelihood of communication issues. The simulation model used for full field modelling gives a representative forecast for expected offtake rate based on local reservoir conditions. South Cowden Unit has varying reservoir rock quality throughout the lease, so comparison of actual offtake with simulation predictions will identify anomalies with expected upper layer productivity.

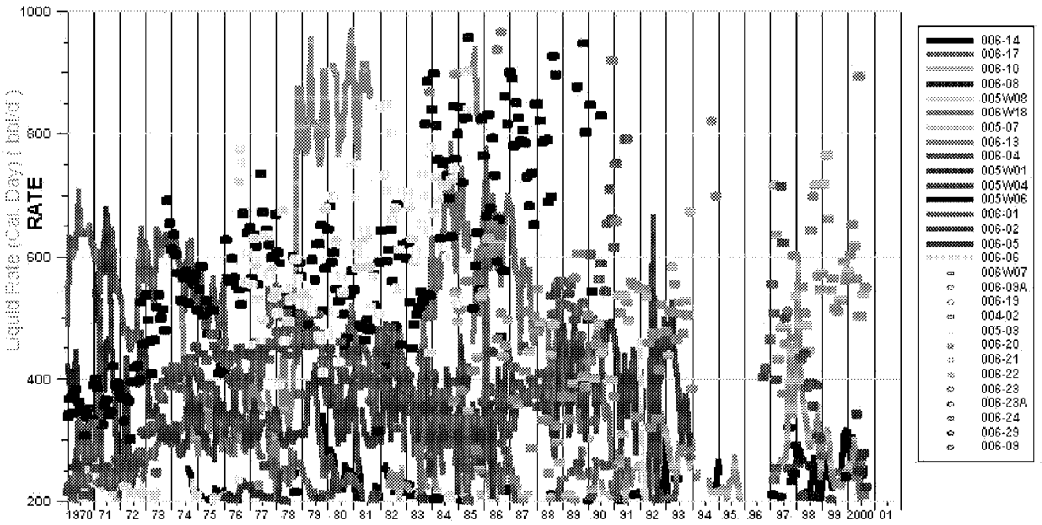
Wells were screened, firstly by offtake rate to identify wells with unusually high offtake. Plots below illustrate well liquid production rate in the various tracts. Identified wells were scrutinized for water cut behaviour and comparison with simulation model predictions. The simulation model predictions predict productivity from the C through F zones, where perforated.

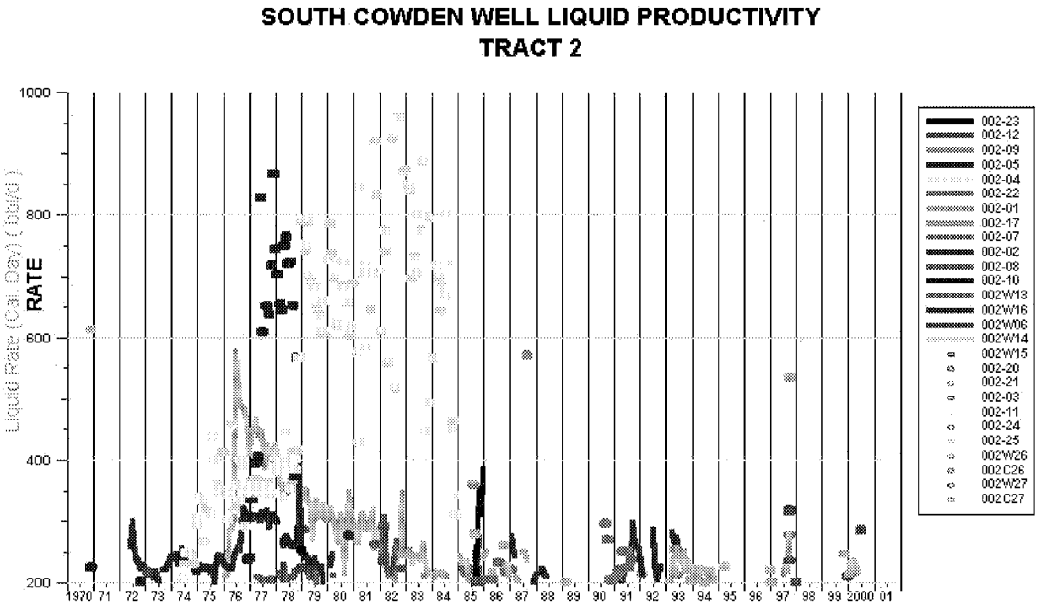
Appendix E

SOUTH COWDEN WELL LIQUID PRODUCTIVITY
TRACT 7 and 8



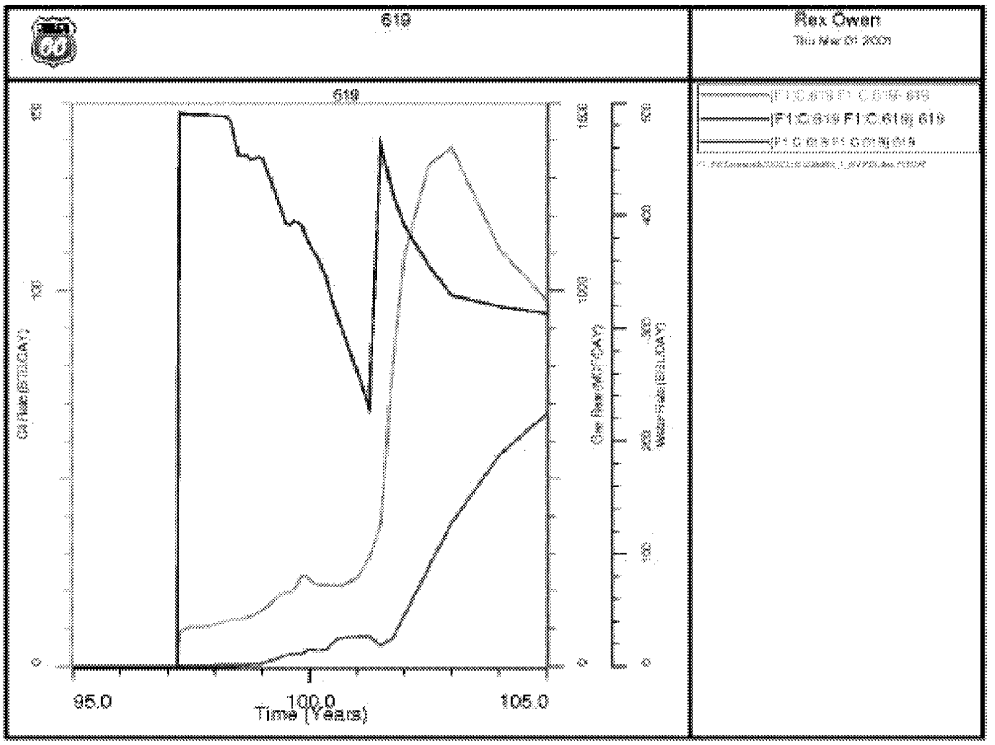
SOUTH COWDEN WELL LIQUID PRODUCTIVITY
TRACT 4, 5 and 6

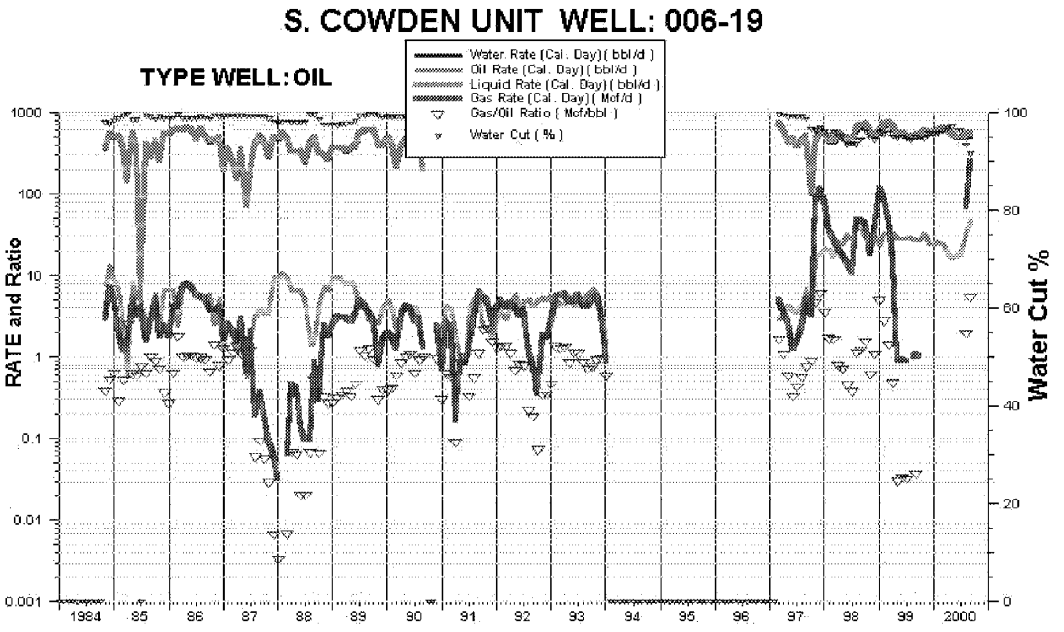




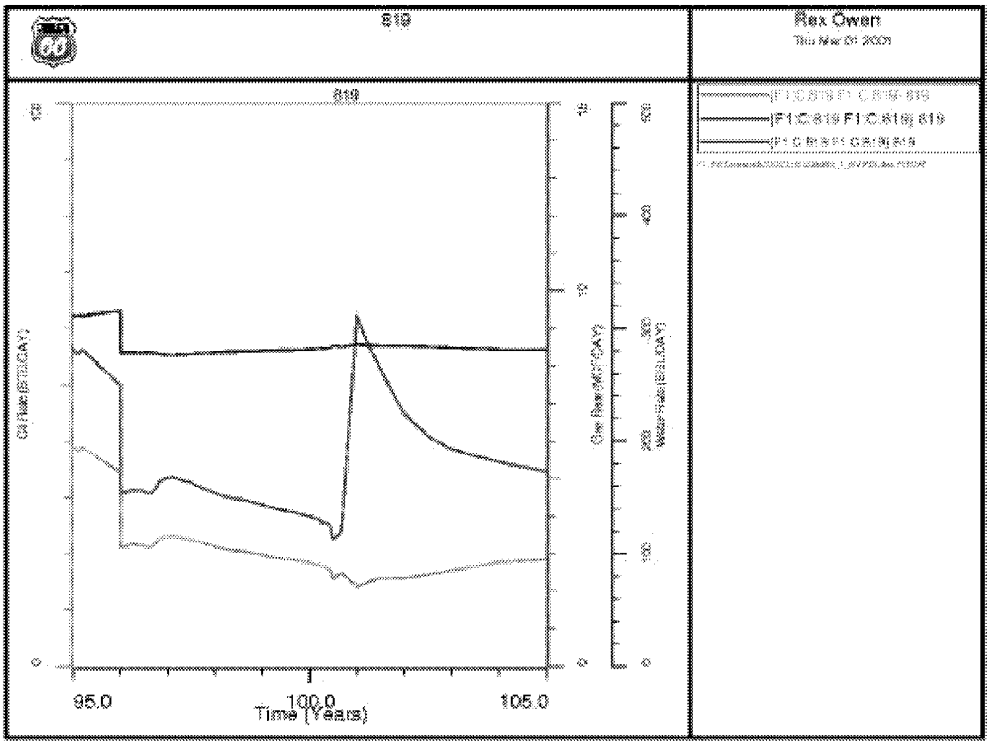
Simulation model comparisons for highly productive wells are illustrated below. Analysis suggests only two wells, 6-19 and 7-08, may have severe communication issues. It is therefore recommended to run radioactive tracer/temperature surveys in these two wells to determine if conformance treatments are required to prevent excessive lower zone productivity.

Appendix E


619
Rex Owen
95.0
100.0
105.0
Time (Years)


S. COWDEN UNIT WELL: 006-19
TYPE WELL: OIL
Water Rate (Cal. Day) (bbl/d)
Oil Rate (Cal. Day) (bbl/d)
Liquid Rate (Cal. Day) (bbl/d)
Gas Rate (Cal. Day) (Mcf/d)
Gas/Oil Ratio (Mcf/bbl)
Water Cut (%)
RATE and Ratio
Water Cut %
1000
100
10
1
0.1
0.01
0.001
100
80
60
40
20
0
1984
85
86
87
88
89
90
91
92
93
94
95
96
97
98
99
2000

Appendix E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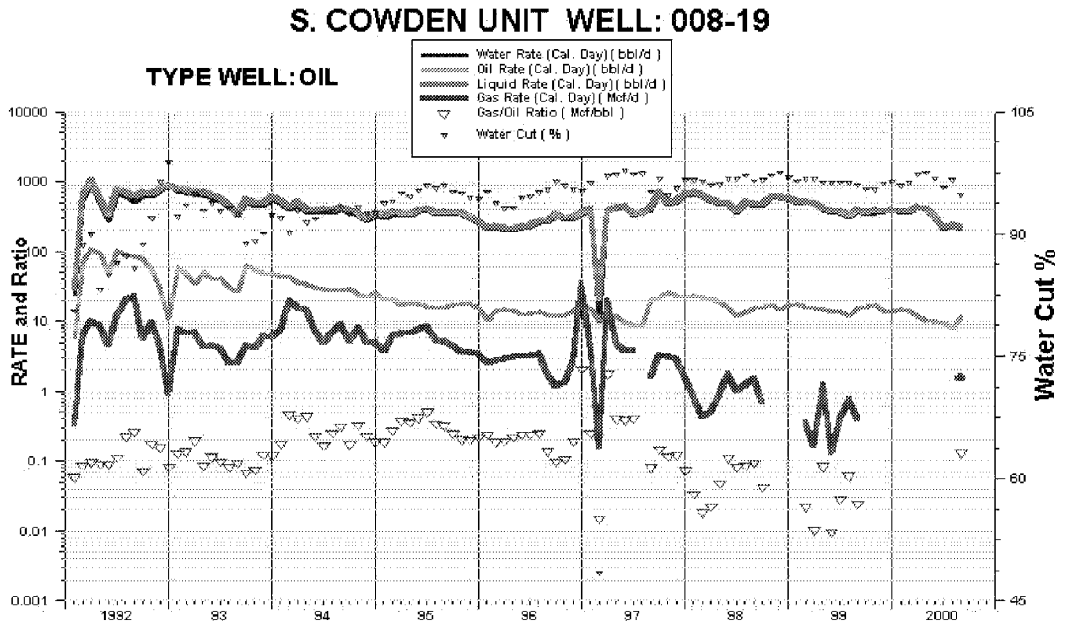
Time (Years)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Gas Rate (Cal. Day) (Mcf/d)
Gas/Oil Ratio (Mcf/bbl)
Water Cut (%)
RATE and Ratio
Water Cut %
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1000
100
10
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0.1
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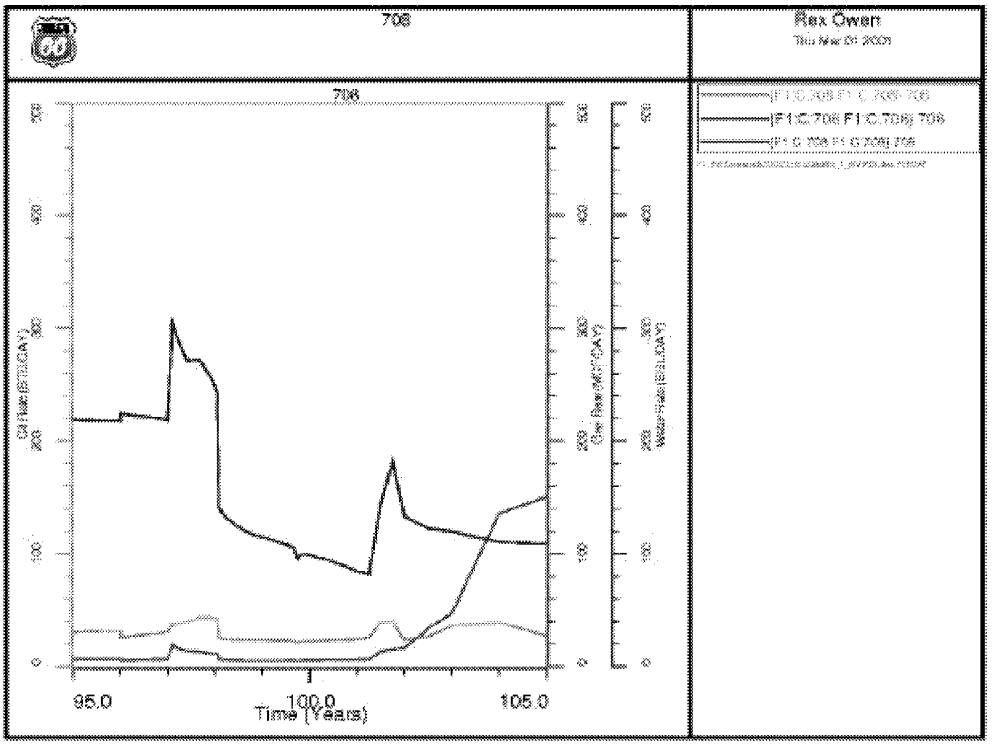
90
75
60
45
1992
93
94
95
96
97
98
99
2000

Appendix E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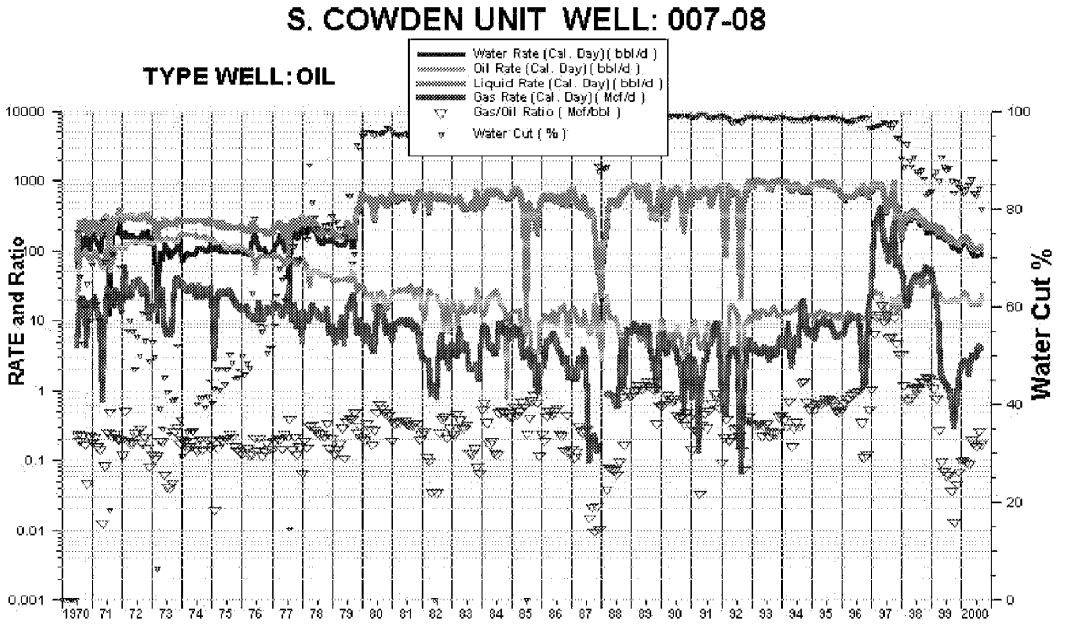
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Gas Rate (Cal. Day) (Mcf/d)
Gas/Oil Ratio (Mcf/bbl)
Water Cut (%)
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Water Cut %
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100
10
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0.1
0.01
0.001
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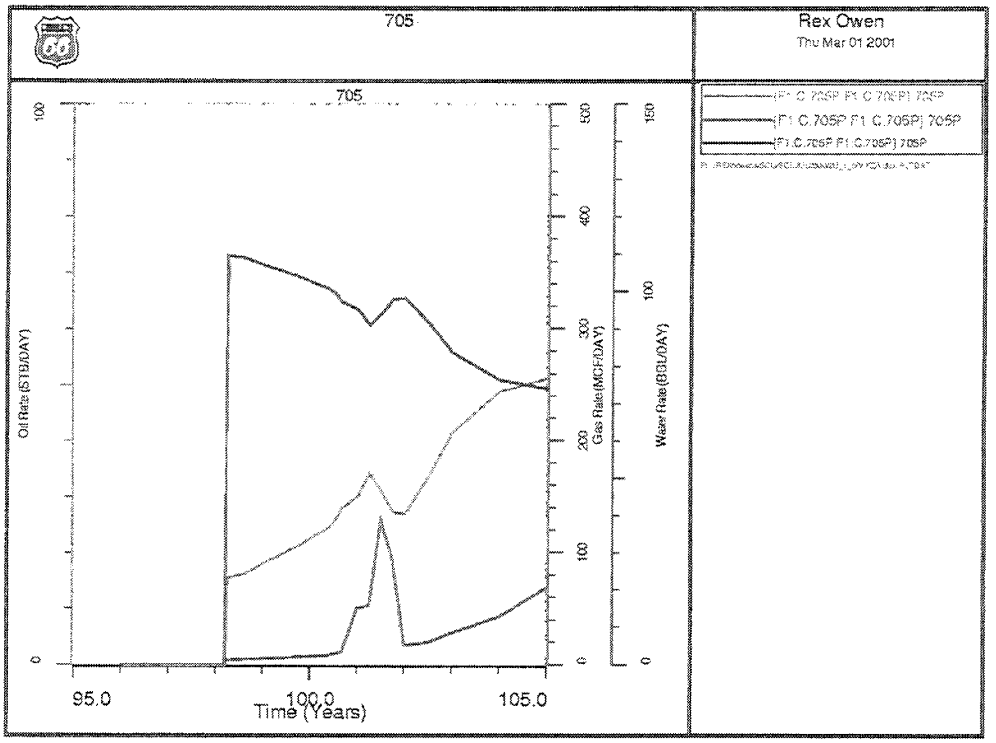
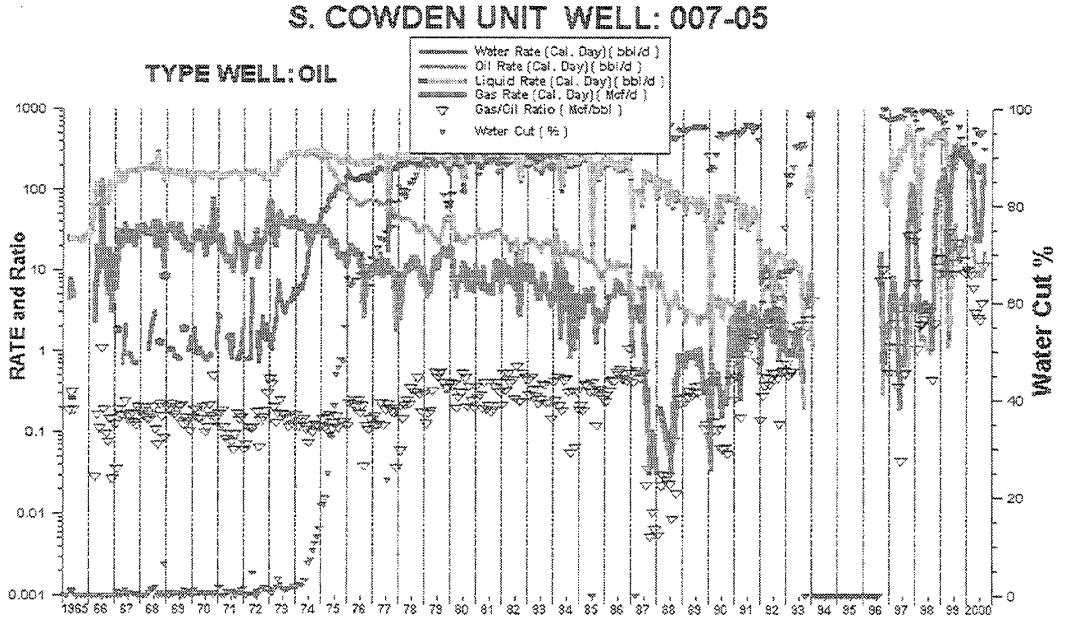
Appendix E





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APPENDIX F

South Cowden Fracture Growth Study

Phillips Petroleum

South Cowden Field
Ector County, West Texas

February, 2001

South Cowden Fracture Growth Study

Draft

Report

for

Phillips Petroleum

Report Date: February 21, 2001

By

Pinnacle Technologies, Inc.
600 Townsend St., Suite 160W
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1. Summary, Conclusions, and Recommendations

In this study Pinnacle Technologies evaluated potential fracture growth geometries resulting from water injection into the San Andres formation, South Cowden field in West Texas. The field is a mature waterflood and CO_2 injection was initiated in 1995. The San Andres formation is a sequence of dolomites, anhydrites and sands at a depth of about 4,500 to 4,800 feet. The main objective of this study was to determine if fractures grow downward from the principal pay zones (San Andres C, D, E, F and G) into the water-bearing higher permeability A and B zones. Based on open-hole injection test data Phillips suspects that downward fracture growth may be occurring due to increased stresses in the pay zones. The study was performed using a 3-D hydraulic fracture model and data from stress logs, minifrac injection tests, pore pressure estimates and core studies.

Conclusions

1. **What is the rock stress profile and how does it change with pore pressure changes?**

   Stress logs seem to indicate that the E section is currently the zone with the highest rock stress (0.61 psi/ft). Stresses are lower both above (F & G sections) and below (A, B & D sections). Stresses in the C zone are close to the ones in the E zone. Modeling the effect of pore pressure changes on rock stresses indicates that the E section had very low stress (0.46 psi/ft) at the beginning of the waterflood (1970 –1980) and increased over time as the waterflood increased pore pressure.

2. **Will waterflood induced fractures grow downward into the water-bearing A & B sections?**

   Fracture modeling indicates that the potential for downward fracture growth is limited to a stress state encountered from 1990 to 2000 and will only take place if the fracture initiates below the E section. Our simulations show that downward fracture growth happens at both 24,000 bbls/mth injection rates and higher 44,000 bbls/mth rates. Initiation below the E section will only happen if the interval is actually perforated below the E section or if a cement channel or plugged perforations change the point of initiation. Downward growth could also happen if a natural fracture acts as a conduit. The injection test in the SC 6-23 was open hole and hence the fracture probably initiated below the E section. On the other hand if the fracture initiates above the high stress E section, the fracture cannot grow down through it. Thus, high stress in the E section makes it a barrier for both downward fracture growth, if fractures initiate in the F & G interval, and upward growth if fractures initiate below in the D section. Initiation in the F & G interval will actually create the tendency for fractures to grow upward

(The SC 6-26 had a possible "channel" resulting in communication with a sand above the pay section).

3. What are the model predicted fracture geometries?

Fracture lengths range from 250 ft to 1050 ft and heights from 45 ft to 170 ft. This range of fracture lengths comes close to current well spacing. Fractures tend to be longer for the higher rate injections (1bbl/min). In general, our simulations show that within the timeframe of 2 to 3 weeks of injection fracture growth reaches an "equilibrium state", where leakoff rate equals the injection rate, thus not creating any new fracture area and in some cases causes length recession.

Recommendations

?? Fracture modeling shows that only perforating the F, G and top part of the E section could eliminate the potential for downward fracture growth into the water-bearing A & B intervals. However, this may create fractures that tend to grow upwards out-of zone, which could also cause some inefficiencies. Also the D and C section and lower part of the E section will probably not be flooded properly.

?? We highly recommend actual measurements of fracture growth with tiltmeter or microseismic fracture mapping. Fracture modeling includesmany assumptions and limitations. Unfortunately, in many cases observed fracture growth is very different from modeling predictions. Pinnacles fracture diagnostic suite of tiltmeter and microseismic fracture mapping enables the measurement of actual frraure growth and geometry. Based on these measurements it is possible to develop a calibrated fracture model, which honors the actual geometry and pressure measurements. A properly calibrated model is a powerful tool, which can then be used to effectively characterize and optimize fracture growth in secondary recovery operations. In the Appendix we have included two SPE papers detailing fracture diagnostic work for TotalFina and Marathon in West Texas waterfloods.

?? Fracture modeling shows the potential for creating long fractures within the pay interval. Therefore well spacing and placement strategies should take fracture lengths and azimuths into consideration. Fracture azimuth can be effectively measured with surface tiltmeters (see SPE papers with West Texas case studies in Appendix).

2. Fracture Analysis

Fracture modeling was performed using the 3-D hydraulic fracture simulator FracProPT. We used well data from the South Cowden (SC) 6-23 as a typical reference well. Other data used in the study included:

- ?? Well logs from the SC 6-23,
- ?? Stress log from the SC 7-10,
- ?? Minifrac injection data from the SC 623 and 6-21,
- ?? Estimates of reservoir pressure history for South Cowden field,
- ?? Injection rate and injection pressure histories typical for the South Cowden field

2.1 Input Data

2.1.1 Hydraulic Fracture Model

In 1998 Pinnacle used tiltmeter fracture mapping diagnostics in the North Robertson field, West Texas to quantify hydraulic fracture geometries. Based on those measured geometries we developed a calibrated hydraulic fracture model. The model calibration settings included fairly small fracture tip effects, which create low fracturing net pressures. Since the injections in the San Andres are fairly low rate injections (in terms of hydraulic fracturing) we feel that the use of this calibrated model with small tip effects is the most appropriate for this application. Also, the open hole minifrac injection tests performed in the SC 6-23 and 6-21 seem to indicate initially low net pressures of about 50 psi. However, the model includes many limitations and assumptions and we highly recommend actual measurements of fracture growth with tiltmeter and/or microseismic fracture mapping.

2.1.2 Fracture Growth Simulations

Hydraulic fracture growth was modeled at discrete points in time throughout the history of the South Cowden waterflood. We performed discrete fracture growth simulations in the years 1970, 1980, 1990, and 1994-2000. Phillips provided Pinnacle with a history of reservoir pressures in the South Cowden field. It shows how pore pressure has increased over time due to waterflooding. Changes in pore pressure will also result in changes of rock stresses, which may cause changes in hydraulic fracture growth behavior. Therefore, we selected the above time intervals to reflect the

historical change of pore pressure and rock stresses and model fracture propagation at those specific times. The time period between 1994 and 2000 was assumed to have no significant changes in pore pressure and rock stresses. The injections were siimulated using about 17,000 bbls of water pumped at 0.55 bbl/min (24,000 bbls/mth) for 21 days and 1 bbl/min (44,000 bbls/mth) for 11 days. These injection rates were selected based on a review of typical water injection data, with one rate being an average value and the other rate being on the high side of water injection rates.

2.1.3 Rock Properties Profile

In order to properly model three-dimensional hydraulic fracture growth it is necessary to have a detailed rock stress profile. Phillips provided Pinnacle a 1994 stress log from the SC 7-1. **Table 1** shows the rock mechanical profile for the SC 7-10. The log-derived dynamic Young's modulus was reduced by 50% to obtain the static Young's modulus. This profile was then used as a reference to create the respective rock mechanical profile for the SC 6-23.

Table 1. Rock mechanical properties profile from stress log in SC 7-10

	Zone	Stress (psi)	Dyn. Young's (psi)	Static Youngs (psi)	Poisson's ratio	Stress Gradient (psi/ft)
4500-4550	Anhyd.	3012	12.9	6.4	0.3	0.666
4550-4571	Anhyd.	2787	14	7	0.3	0.611
4571-4591	Sand/An.	3045	9.2	4.6	0.27	0.665
4591-4612	G	2820	14	7	0.29	0.613
4612-4625	Dol/An.	2767	13.4	6.7	0.3	0.6
4625-4642	F	2957	10.2	5.1	0.3	0.638
4642-4647	Sand/An.	2526	9	4.5	0.23	0.544
4647-4710	E	3197	7.3	3.6	0.32	0.683
4710-4783	D	2994	8.2	4.1	0.3	0.631
4738-4743	Sand/An.	2788	8.2	4.1	0.26	0.588
4743-4756	C	3181	8	4	0.32	0.67
4756-4761	Sand/An.	2847	7.8	3.9	0.26	0.598
4761-4829	B	2949	9.4	4.7	0.31	0.615
4829-4865	A	2846	10	5	0.29	0.587

Due to uncertainties associated with rock stresses obtained from stress logs it is necessary to calibrate those measurements with actual injection data and apply appropriate corrections. We used the open-hole minifrac injection test and acid breakdown in the SC 6-23 to calibrate those stress values. The openhole injection test showed a stress gradient of about 0.55 psi/ft in the A & B zones. The acid job was performed in the E & F zones and showed a gradient of about 0.61 psi/ft. Both numbers are lower than the ones obtained from the stress logs (0.66 psi/ft average for

E & F and 0.6 psi/ft for A & B). The stress log values in both zones were multiplied by 0.92 to obtain the actual stress values of the injection tests. **Table 2** and **Figure 1** show the final corrected stress profile for the SC 6-23, which was used in the fracture simulations for the years 1994-2000. The stress profiles for 1970,1980 and 1990 were derived from this profile after applying the appropriate stress corrections due to pore pressure changes. Also included in **Table 2** is a profile of leakoff coefficients (Total C), which were calculated from core permeability measurements and other reservoir properties such as pore pressure. However, initial simulations showed that fluid leakoff was very high making it impossible to propagate a hydraulic fracture. Therefore, we reduced the core permeability measurements by a factor of 5, which is not uncommon in many reservoirs when comparing core and actual reservoir permeabilities (relative permeability effects of injected phase).

Table 2 and Figure 1 shows that the E zone has the highest rock stresses. Stresses are lower both above (F & G) and below (A, B & D). Stresses in the C zone are close to the ones in the E zone. The modified rock stress profiles for 1970,1980, and 1990 are shown in **Figures 2 to 4** and show how lower reservoir pressures affect the stresses in the pay zones. We used the following pore pressure history to modify the stress profile:

1970	450 psi
1980	850 psi
1990	1950 psi
1994	2340 psi

The following equation was used to approximate the historical change of rock stresses based on pore pressure changes:

$$S_h = ???????(S_v - ?P) + ?P$$

where: P = pore pressure
S_h = minimum horizontal stress
S_v = vertical stress (1.05 psi/ft* Depth)
$?$ = Poisson's Ratio

The calculations show that in 1970 and 1980 the stresses in the E zone may have been reduced to values below the bounding layers due to significant pore pressure depletion prior to the waterflood (**Figures 3 and 4**). We assumed that the stresses were unchanged in the bounding zones and A & B layers.

Table 2. Layer properties for South Cowden frac modeling - Reference Well SC 6-23 (Years 1994-2000)

Layer Parameters (1994-2000)								
Layer #	Top of zone (ft)	Stress (psi)	Top of zone (ft)	Young's modulus (psi)	Poisson's ratio	Top of zone (ft)	Total Ct (ft/min½)	PoreFluid perm. (md)
Anhy.	0.0	2737	0.0	6.4e+006	0.30	0.0	2.885e-004	1.00e-002
Anhy.	4465.7	2742	4465.7	6.4e+006	0.30	4465.7	2.885e-004	1.00e-002
Sd/Anhy.	4479.5	2745	4479.5	4.6e+006	0.27	4479.5	2.885e-004	1.00e-002
Anhy.	4490.3	2759	4490.3	6.4e+006	0.30	4490.3	2.885e-004	1.00e-002
Anhy.	4511.7	2536	4511.7	7.0e+006	0.30	4511.7	2.885e-004	1.00e-002
Sd/Anhy.	4513.0	2768	4513.0	4.6e+006	0.27	4513.0	2.885e-004	1.00e-002
Anhy.	4531.2	2554	4531.2	7.0e+006	0.30	4531.2	2.885e-004	1.00e-002
Sd/Anhy.	4557.1	2794	4557.1	4.6e+006	0.27	4557.1	2.885e-004	1.00e-002
G	4572.9	2584	4572.9	7.0e+006	0.29	4572.9	3.871e-003	1.80e+000
Dol/Anhy	4590.5	2536	4590.5	6.7e+006	0.30	4590.5	1.290e-003	2.00e-001
F	4598.7	2708	4598.7	5.1e+006	0.30	4598.7	2.235e-003	6.00e-001
E	4627.0	2915	4627.0	3.6e+006	0.32	4627.0	4.741e-003	2.70e+000
E	4655.2	2933	4655.2	3.6e+006	0.32	4655.2	4.741e-003	2.70e+000
D	4686.8	2731	4686.8	4.1e+006	0.30	4686.8	2.379e-003	6.80e-001
Sd/Anhy.	4715.4	2553	4715.4	4.1e+006	0.26	4715.4	4.080e-004	2.00e-002
C	4722.3	2912	4722.3	4.0e+006	0.32	4722.3	4.080e-003	2.00e+000
Sd/Anhy.	4732.4	2605	4732.4	3.9e+006	0.26	4732.4	6.452e-004	5.00e-002
B	4738.7	2694	4738.7	4.7e+006	0.31	4738.7	5.770e-003	4.00e+000
A	4782.2	2593	4782.2	5.0e+006	0.29	4782.2	9.124e-003	1.00e+001
A	4820.7	2613	4820.7	5.0e+006	0.29	4820.7	9.124e-003	1.00e+001
A	4858.5	2635	4858.5	5.0e+006	0.29	4858.5	9.124e-003	1.00e+001
A	4899.5	2646	4899.5	5.0e+006	0.29	4899.5	9.124e-003	1.00e+001

Appendix F

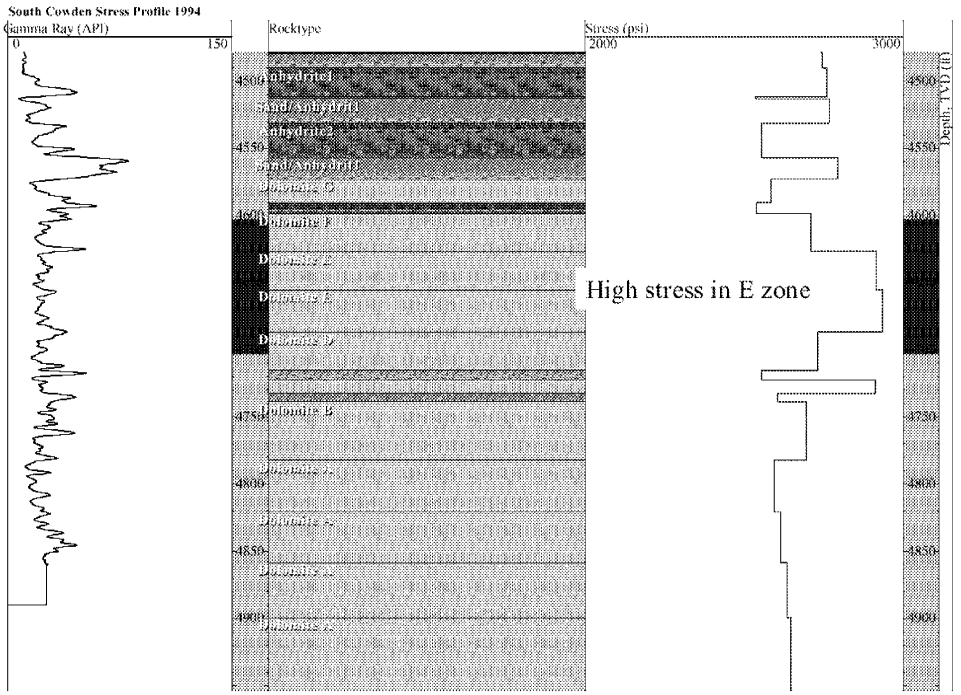

Figure 1. Rock stress profile (Years 1994-2000)

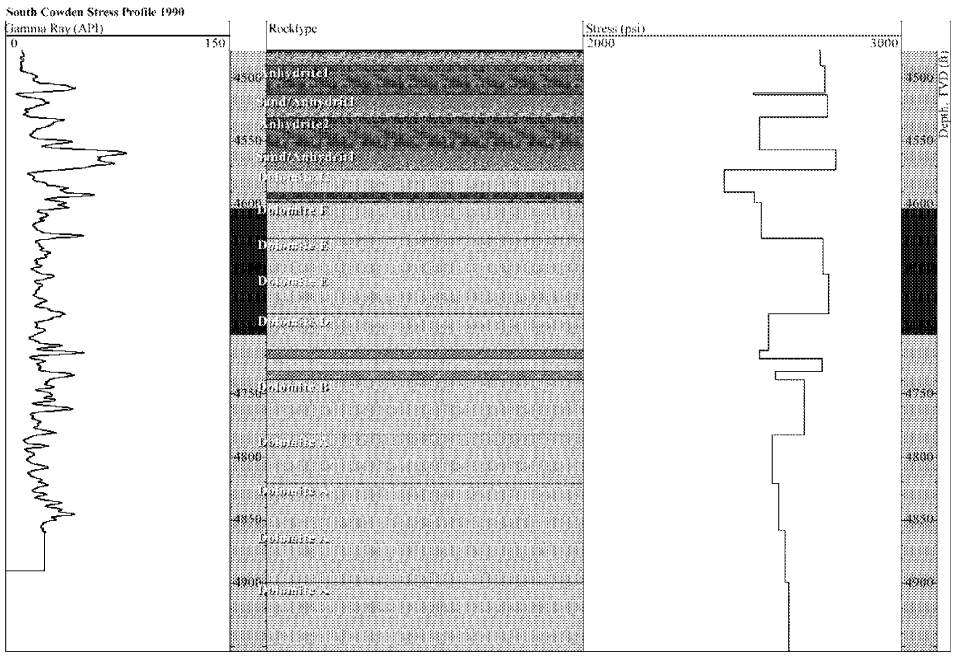

Figure 2. Rock stress profile (Year 1990)

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Appendix F

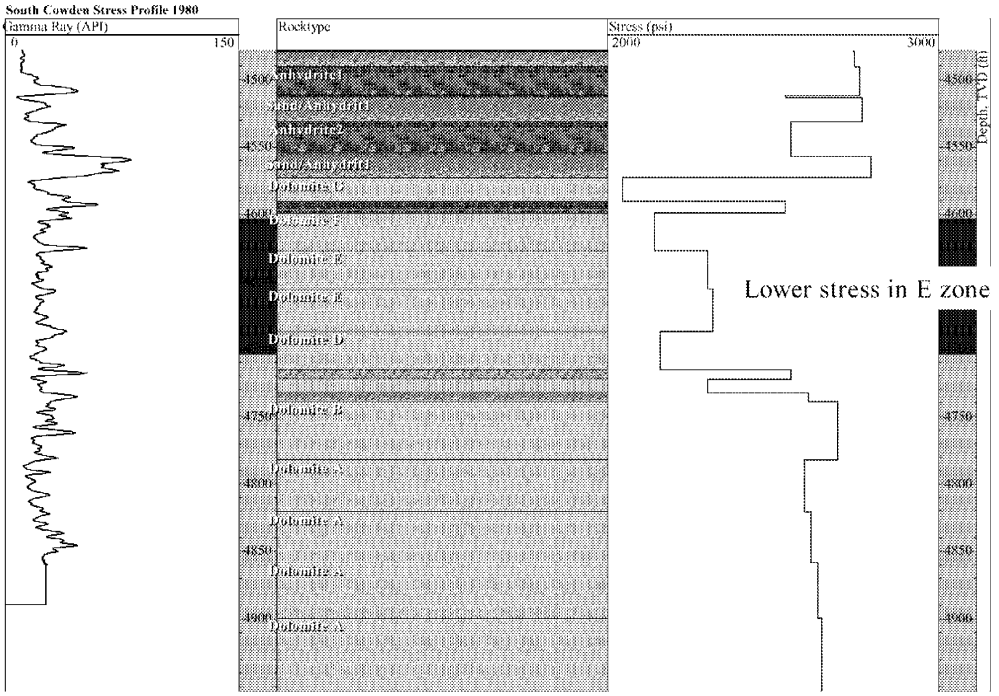

Figure 3. Rock stress profile (Year 1980)

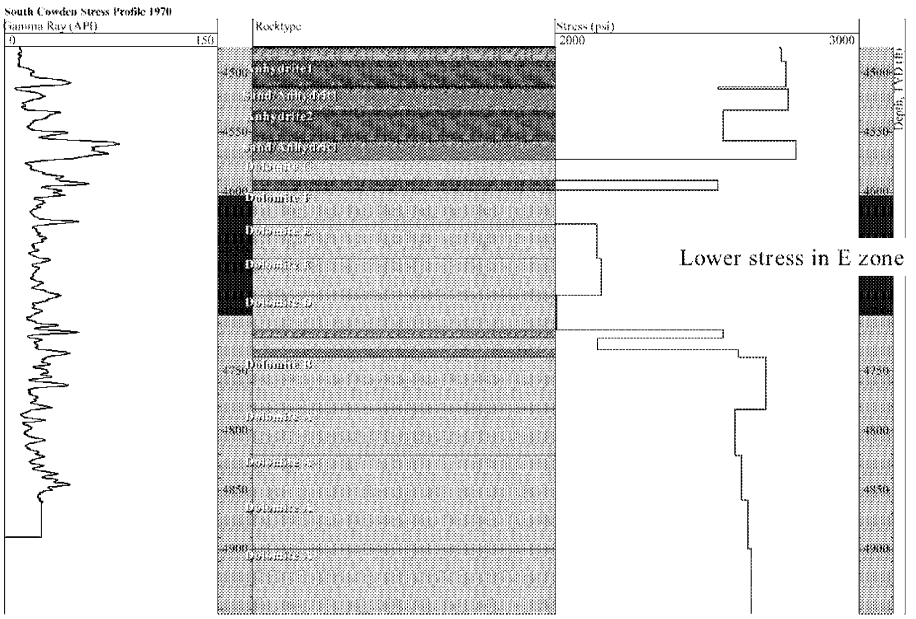

Figure 4. Rock stress profile (Year 1970)

2.2 Fracture Modeling Results

The objective of this study was to determine if fractures could potentially grow down into the water-bearing A & B intervals. After initial scoping simulations, where we varied different parameters such as fluid leakoff, stress profile, perforated interval (location of fracture initiation), and injection rate, we found that the location of fracture initiation, injection rate and stress profile have the biggest impact on the potential for downward fracture growth. Therefore, we performed fracture growth simulations for:

- ?? Stress profiles and pore pressures corresponding to the ones encountered in 1970,1980, 1990 and 1994-2000
- ?? Injection rates of 0.55 bbls/min and 1 bbl/min
- ?? Fracture initiation*below the E zone* and fracture initiation*above the E zone*

2.2.1 Fracture Initiation *Above* the E Section

Fractures preferentially initiate at the point of least resistance or lowest stress. If the interval is very large and stress gradients do not change too much, the fracture will preferentially initiate at the top of the zone since stresses are lower at smaller depths. With everything being equal (no problems with cement or plugged perforations) our simulations show that if the entire interval (G through D) is perforated the fracture will avoid the high stress E zone and initiate above in the F and G sections (valid for time periods 1980 through 2000). **Figures 5 to 16** show the results of fracture growth simulations for all time periods. Each case includes a plot of predicted injection pressures and estimated fracture growth. The plot sequence starts with the 1994-2000-time period and continues back in time (1990, 1980, and 1970).

Overall, the level of surface injection pressures correspond fairly well with actual observed pressures (between 200 and 1200 psi), in spite of large model uncertainties. Facture lengths range from 450 ft to 1050 ft and heights from 65 ft to 165 ft. Fractures tend to be longer for the higher rate injections (1bbl/min). In general, our simulations show that fracture growth reaches an "equilibrium state", where leakoff rate eqials the injection rate, thus not creating any new fracture area and in some cases causing length recession. It is evident from these plots that fractures do not grow down into the A & B section, due to the high stress in the E section acting as a barrier for downward fracture growth. On the contrary, the fractures will actually tend to grow upward into lower stress and lower permeability intervals. It was not possible to simulate 0.5 bbls/min injections in 1970 and 1980 due to substantially increased fluid leakoff, and the model not being able to establish a stable fracture (the injected rate cannot keep up with leakoff). Predicted fracture lengths are shorter in 1970 and 1980. In 1970 the model predicts fracture growth throughout the interval down into the C section but not into the A & B intervals. This is caused by lower stresses in the E section. Also the model injection pressures are lower, only 200 psi to 400 psi in 1970 and 1980, which compares well with historical injection pressures during that same time frame.

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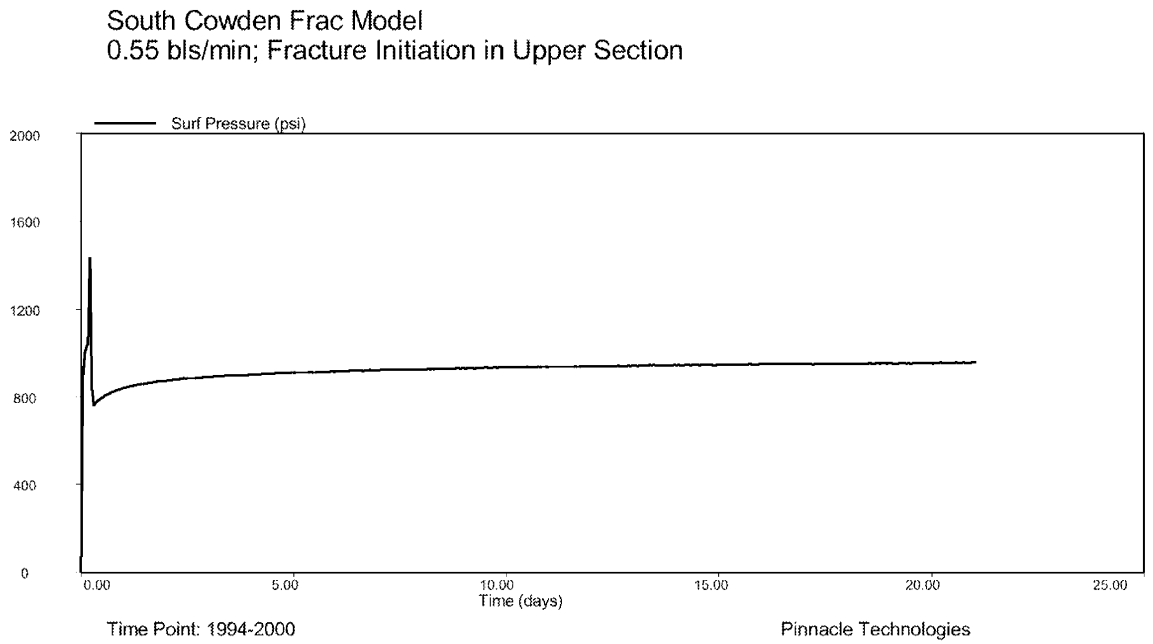

Figure 5. Model injection pressures for 1994-200: Initiation In Upper Section; Rate = 24,000 bbls/mth

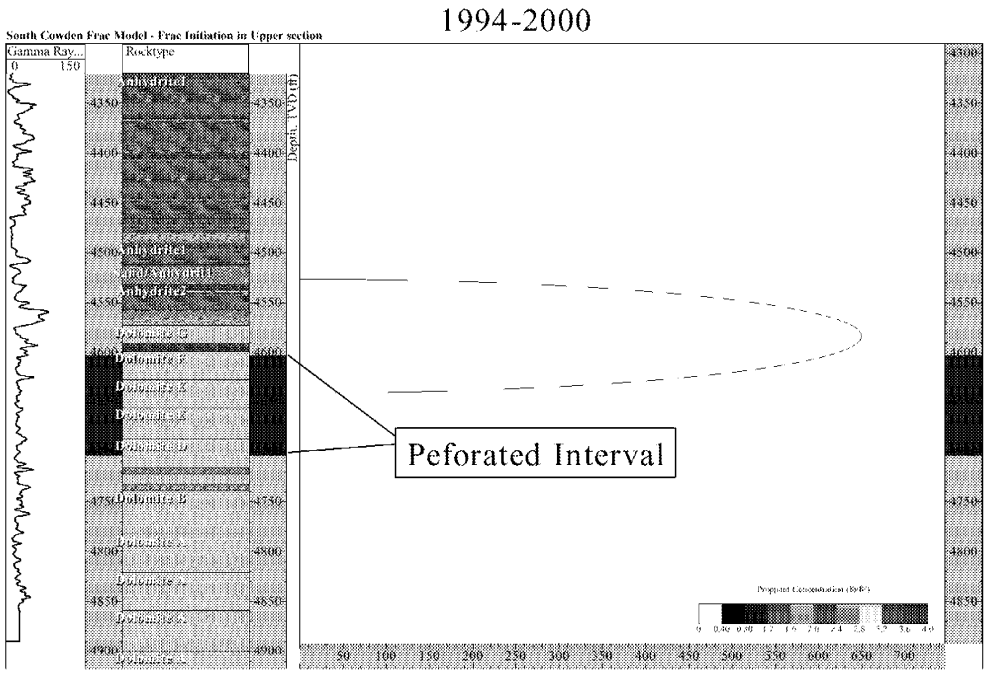

Figure 5.Model fracture geometry for 1994-2000: Initiation in upper section; Rate=24,000 bbls/mth

Appendix F

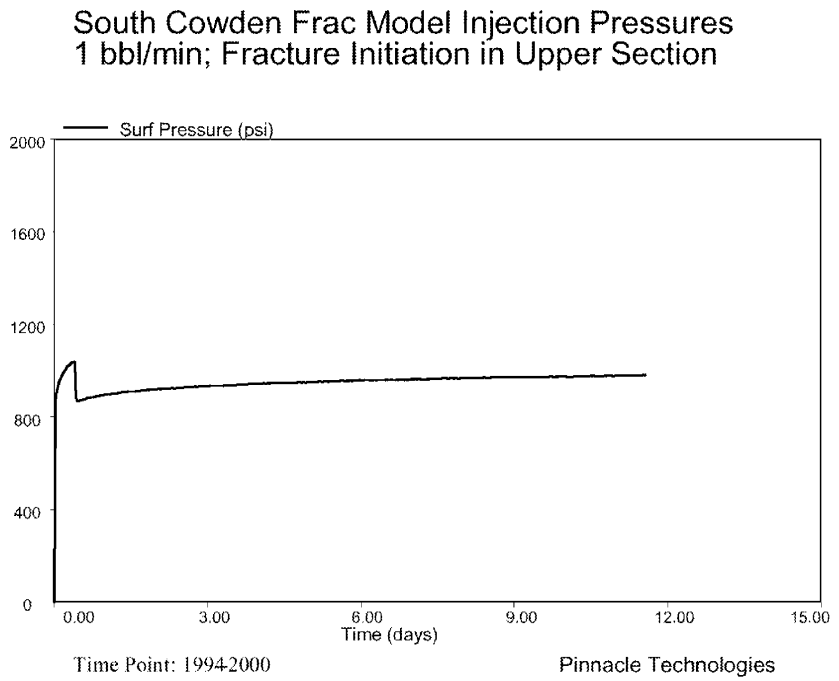

Figure 6.Model injection pressures for 1994-200: Initiation in upper section; Rate=44,000 bbls/mth

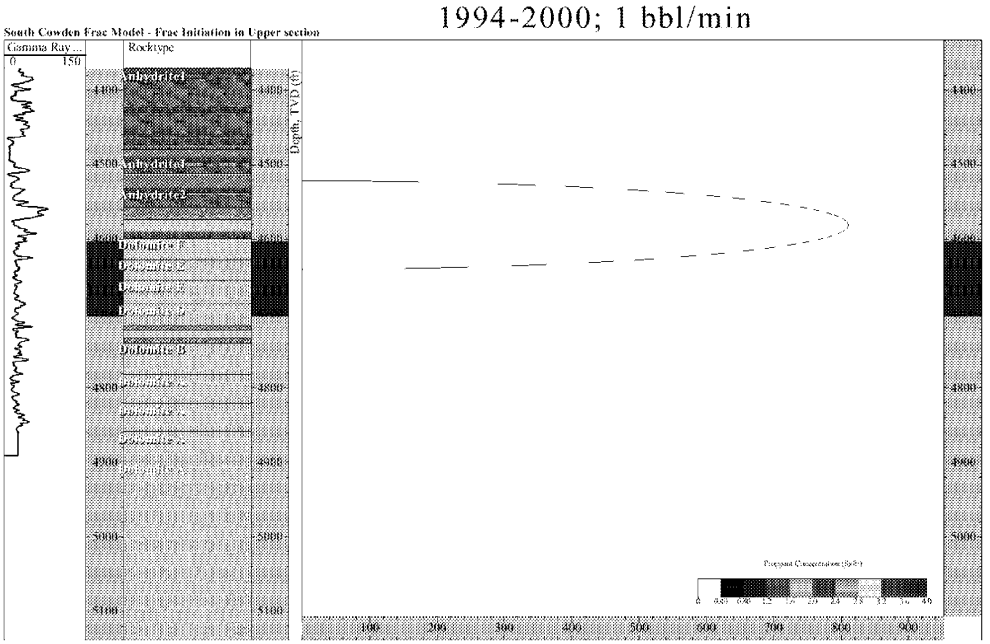

Figure 7. Model fracture geometry for 1994-2000: Initiation in upper section; Rate=44,000 bbls/mth

Appendix F

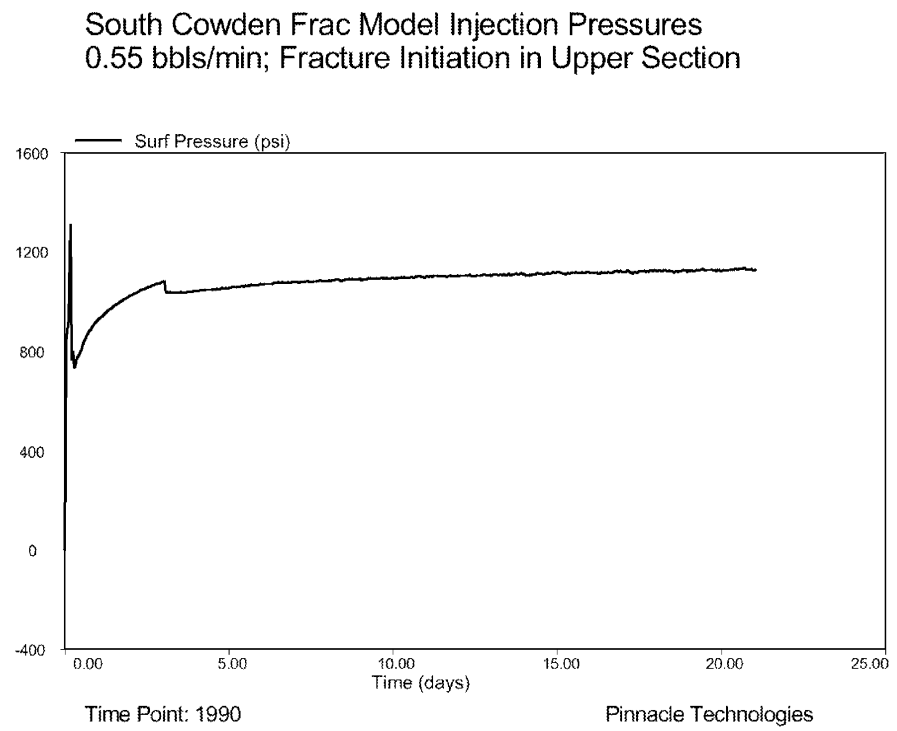

Figure 8. Model injection pressures for 1990: Initiation in upper section; Rate=24,000 bbls/mth

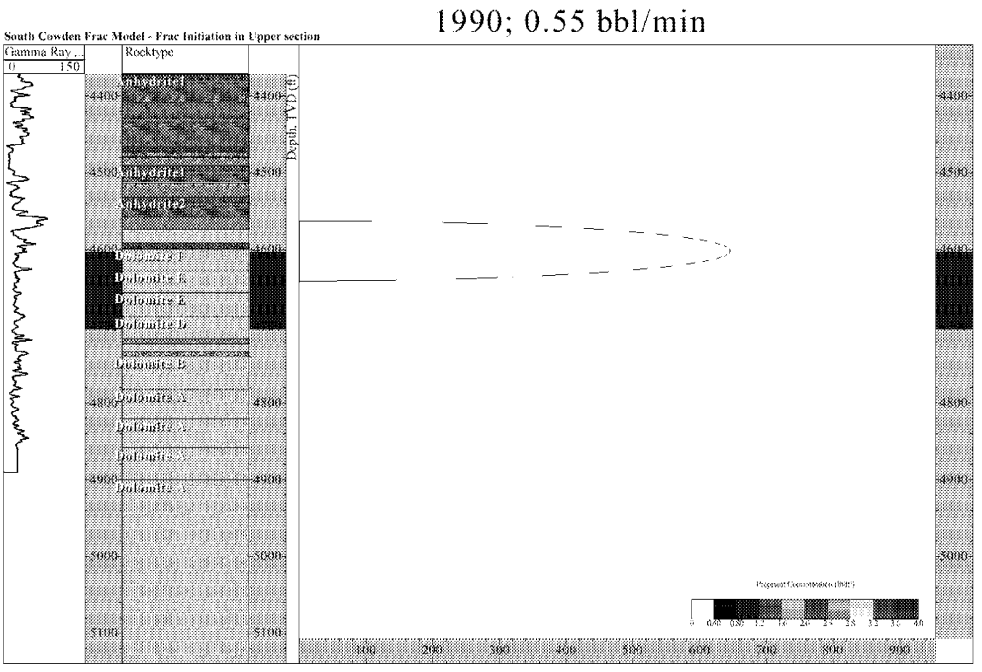

Figure 9. Model fracture geometry for 1990: Initiation in upper section; Rate=24,000 bbls/mth

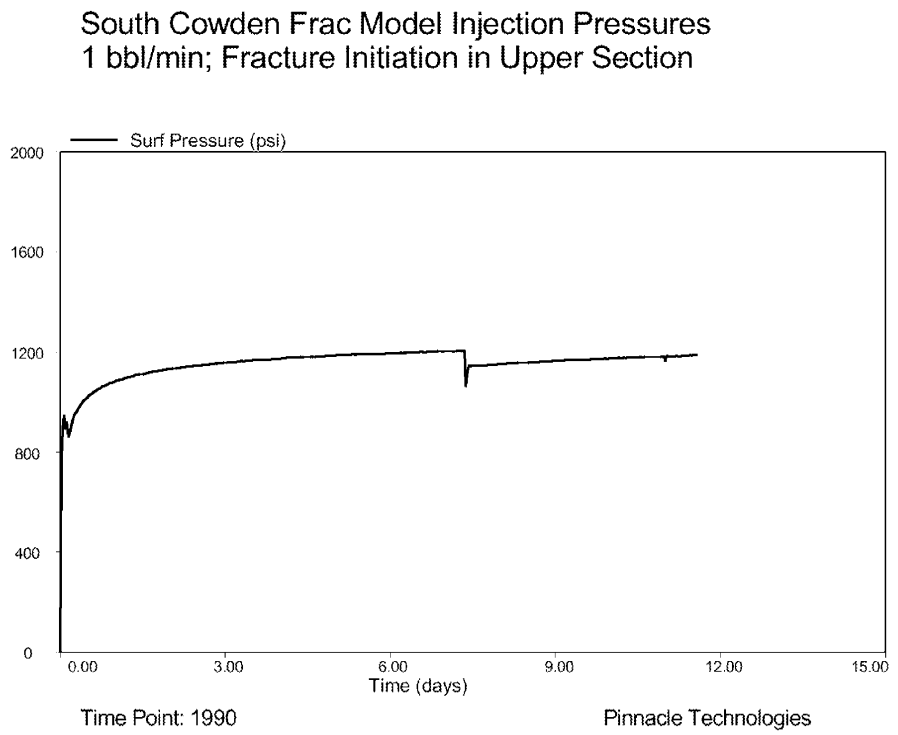

Figure 10. Model injection pressures for 1990: Initiation in upper section; Rate=44,000 bbls/mth

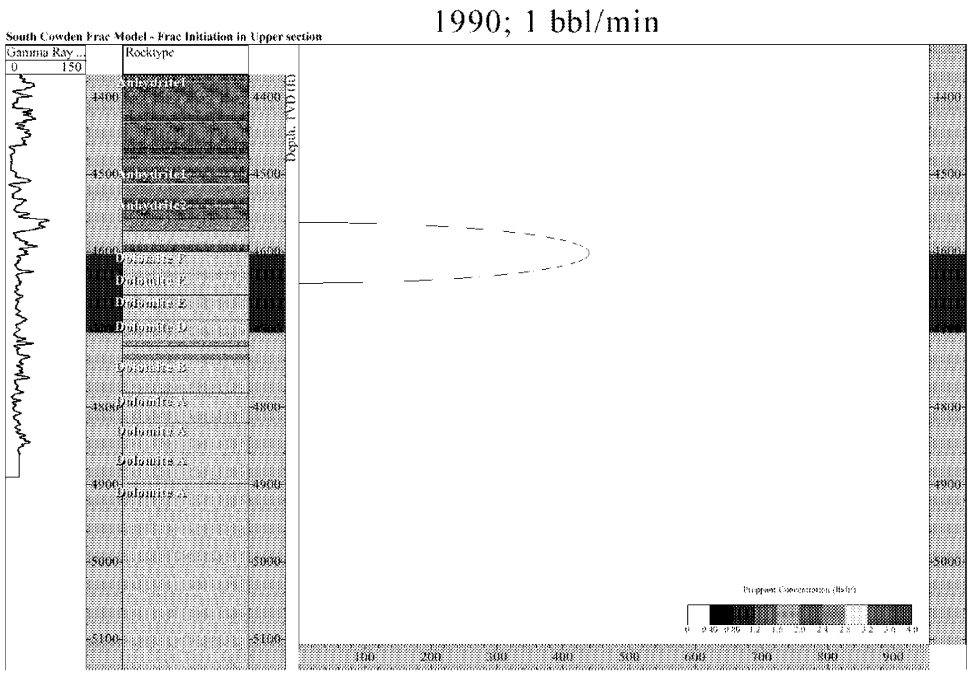

Figure 11. Model fracture geometry for 1990: Initiation in upper section; Rate=44,000 bbls/mth

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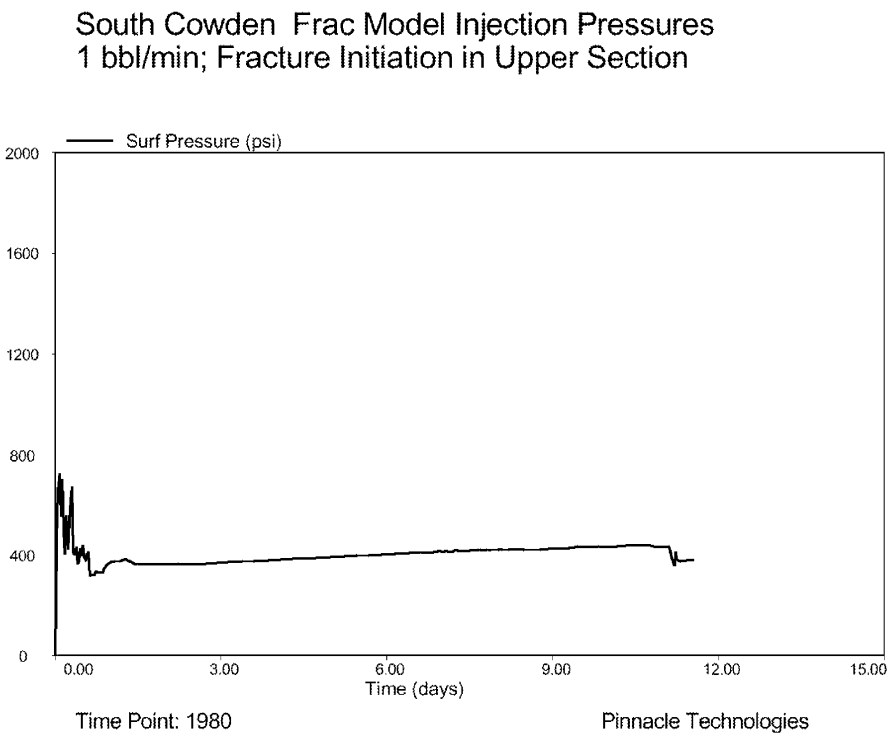

Figure 12. Model injection pressures for 1980: Initiation in upper section; Rate=44,000 bbls/mth

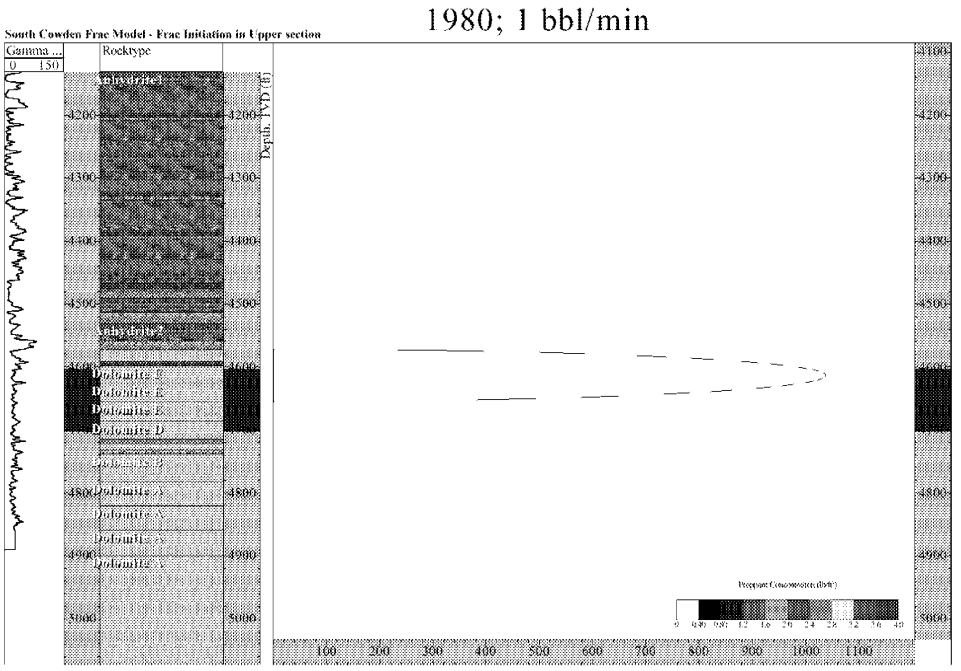

Figure 13. Model fracture geometry for 1980: Initiation in upper section; Rate=44,000 bbls/mth

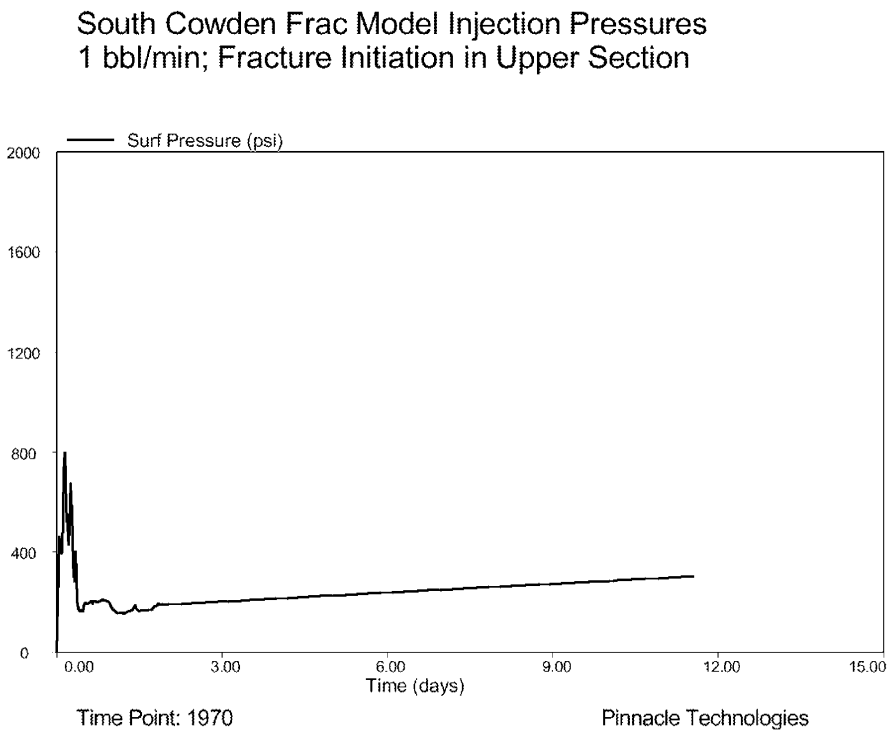

Figure 14. Model injection pressures for 1970: Initiation in upper section; Rate=44,000 bbls/mth

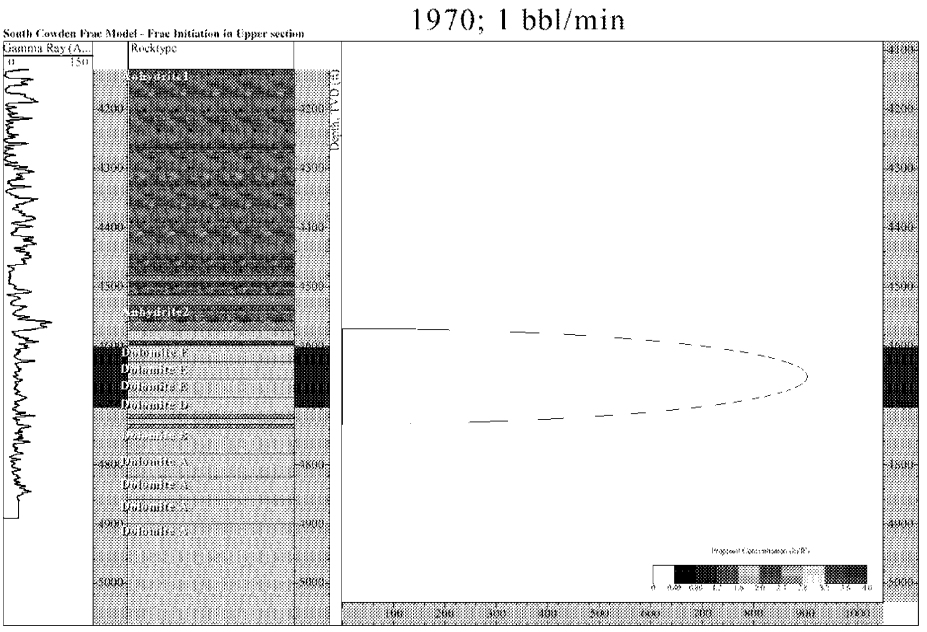

Figure 15. Model fracture geometry for 1970: Initiation in upper section; Rate=44,000 bbls/mth

2.2.2 Fracture Initiation *Below* the E Section

We also simulated the other case where we forced fracture initiation below the E section by only perforating the E and D Section (4,660' to 4,710'). In this case the E section forms an upper barrier for fracture growth resulting in the potentialfor significant downward fracture growth into the A & B sections at least for the time period of 1994-2000 (**Figures 17 to 21**). Interestingly, the level of injection pressures in 1994 (**Figure 17**) is very similar to the one where the fracture initiates above the E section (**Figure 5**). Therefore, it is not possible to distinguish downward fracture growth (**Figure 18**) from upward fracture growth (**Figure 6**) based on the level of injection pressures. Also, the modeling indicates that downward fracture growth becomes less significant in 1990 (**Figures 22 to 25**) and does not happen in 1970 and 1980 (**Figures 25 to 32**). However, the 1970 and 1980 simulations predict injection pressures, which are substantially higher (1,400 psi to 1,600 psi due to contained fracture growth within D & E interval) than the actual ones (200 psi to 400 psi). This makes the fracture growth scenario of contained fracture growth below the E section very unlikely for those time periods (**Figures 25 to 32**).

Fracture lengths range from 280 ft to520 ft and heights from 45 ft to 170 ft. Again, fractures tend to be longer for the higher rate injections (1bbl/min) and fracture growth reaches an "equilibrium state", where leakoff rate equals the injection rate, thus not creating any new fracture areaand in some cases causing length recession.

Appendix F

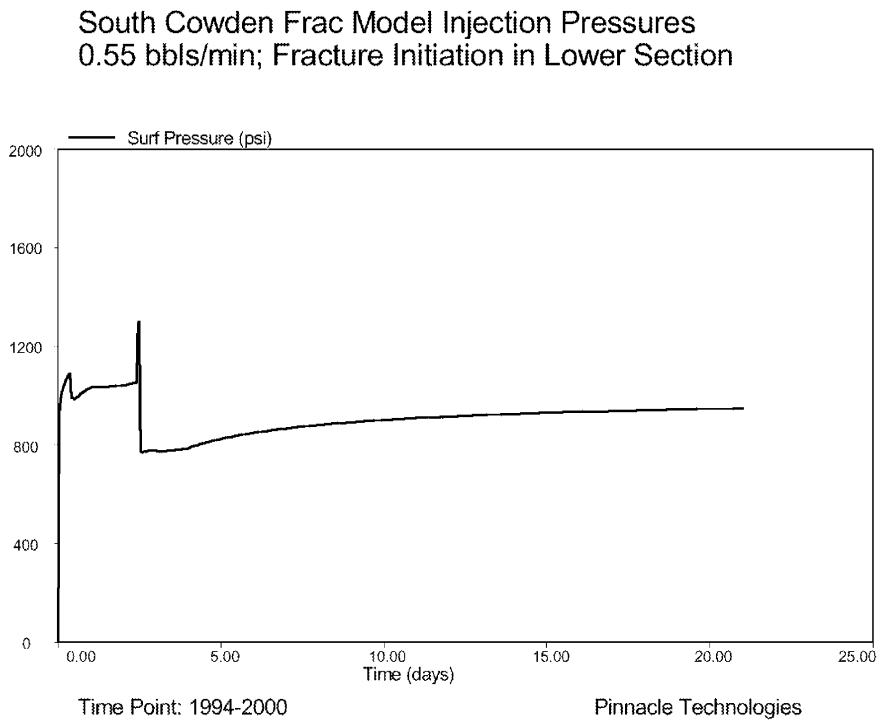

Figure 16.Model injection pressures for 1994-2000:Initiation in lower section; Rate=24,000 bbls/mth

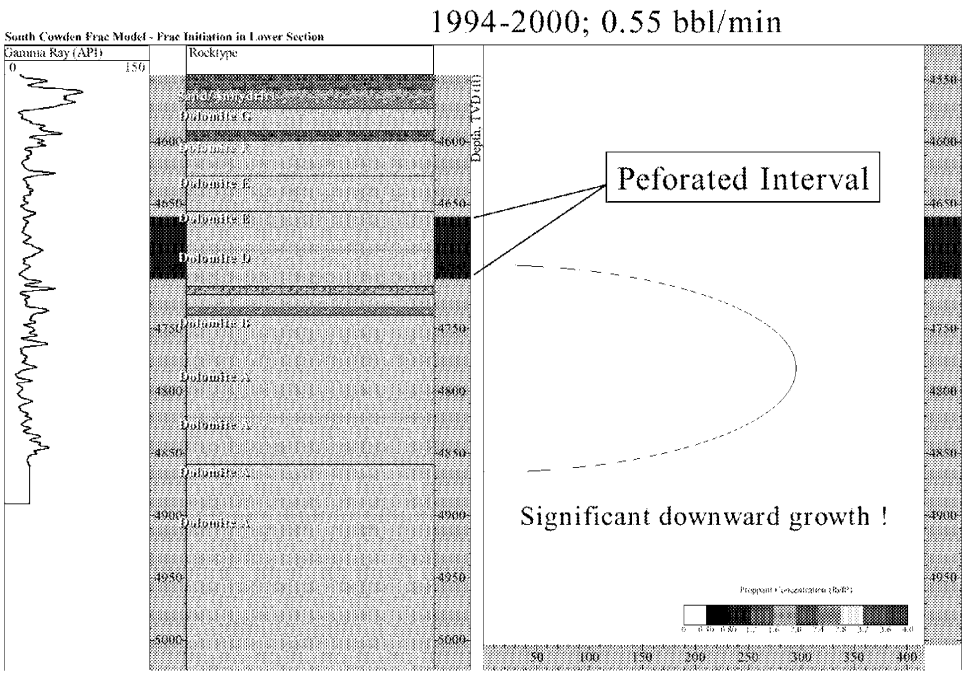

Figure 17. Model fracture geometry for 1994-2000: Initiation in lower section; Rate=24,000 bbls/mth

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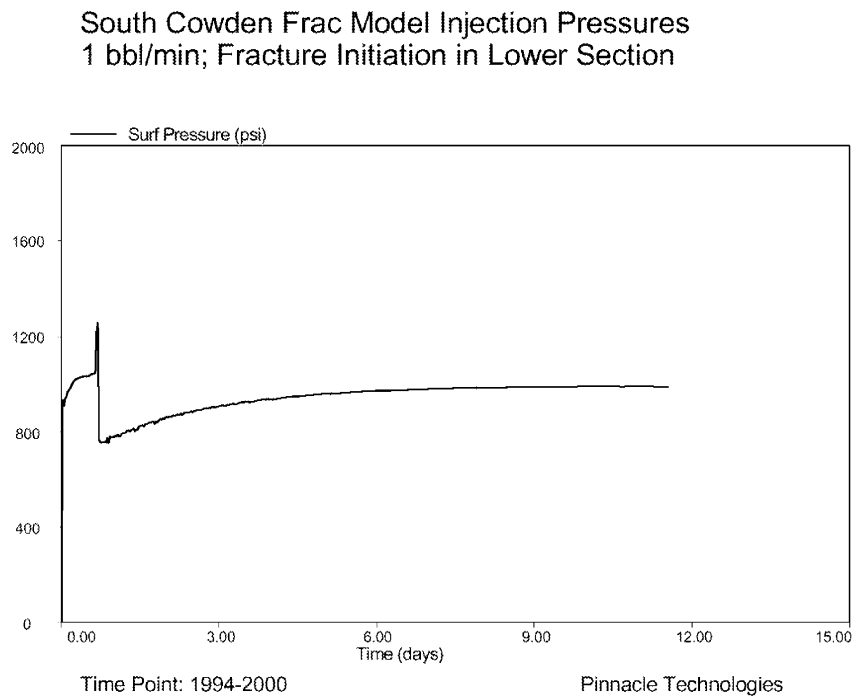

Figure 18. Model injection pressures for 1994-2000:Initiation in lower section; Rate=44,000 bbls/mth

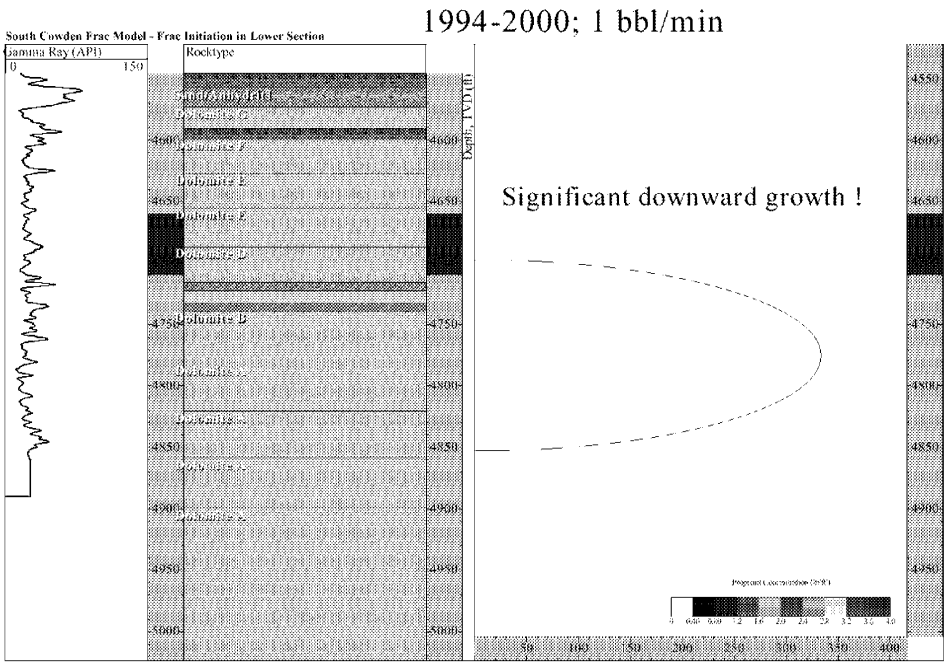

Figure 19. Model fracture geometry for 1994-2000: Initiation in lower section; Rate=44,000 bbls/mth

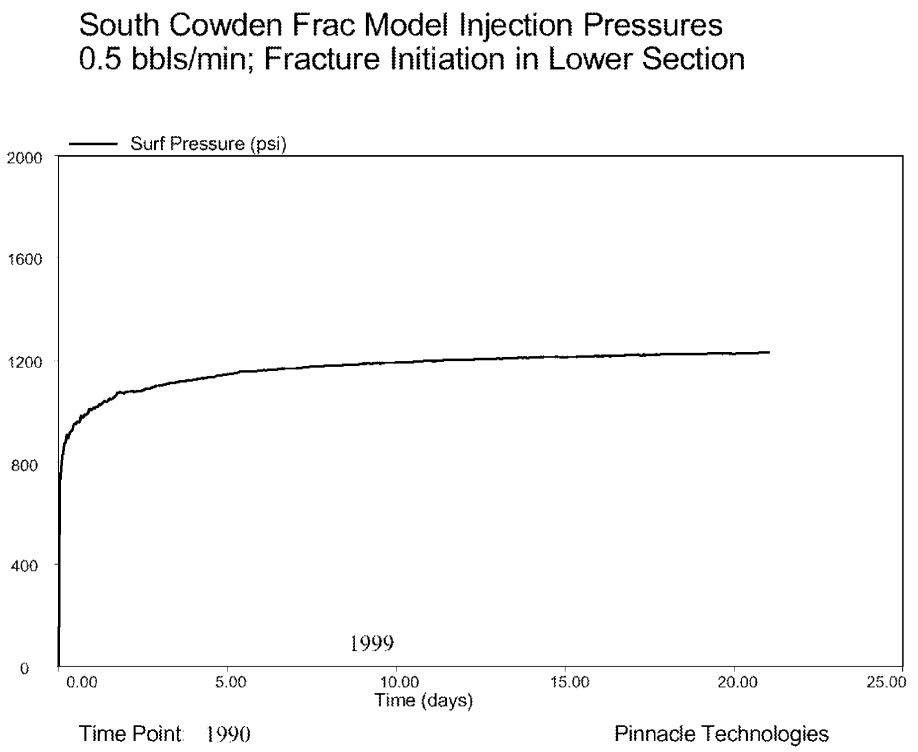

Figure 20. Model injection pressures for 1990: Initiation in lower section; Rate=24,000 bbls/mth

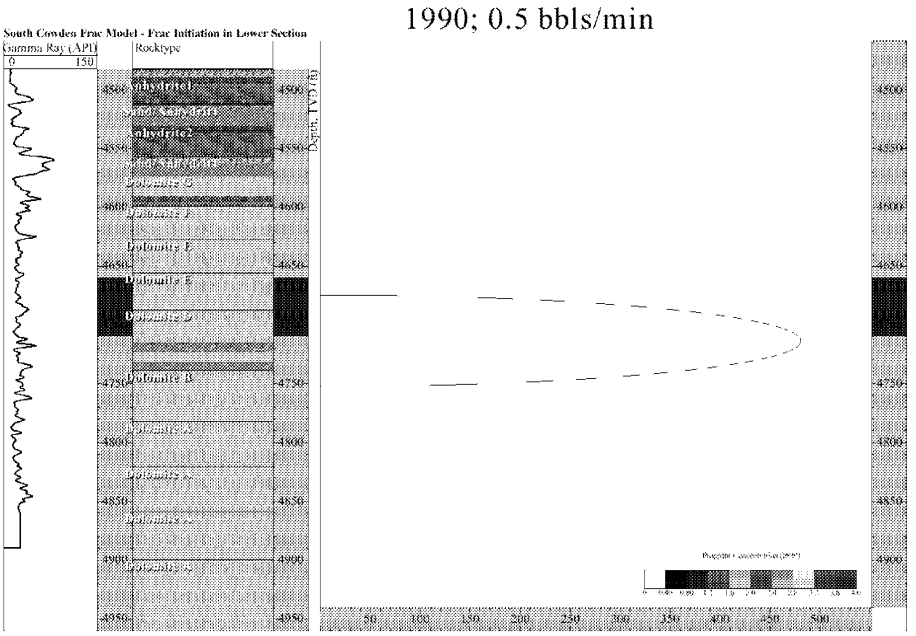

Figure 21. Model fracture geometry for 1990: Initiation in lower section; Rate=24,000 bbls/mth

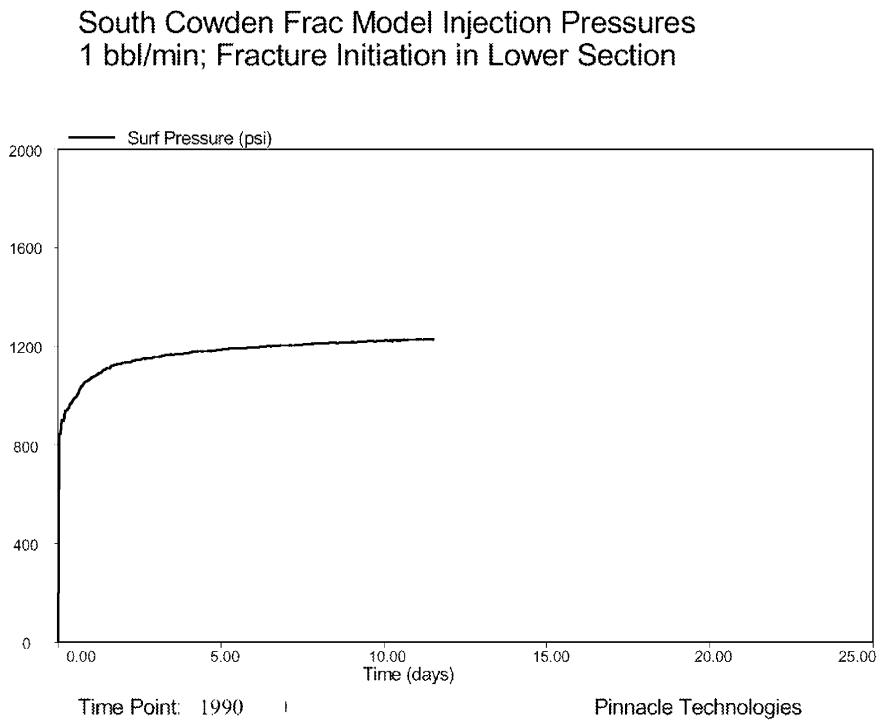

Figure 22. Model injection pressures for 1990: Initiation in lower section; Rate=44,000 bbls/mth

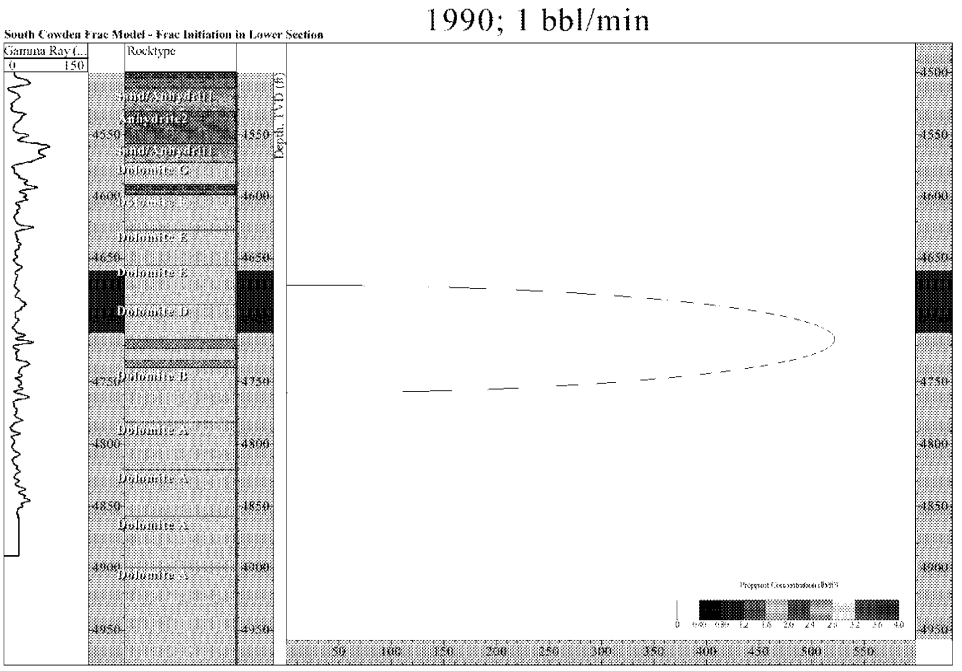

Figure 23. Model fracture geometry for 1990: Initiation in lower section; Rate=44,000 bbls/mth

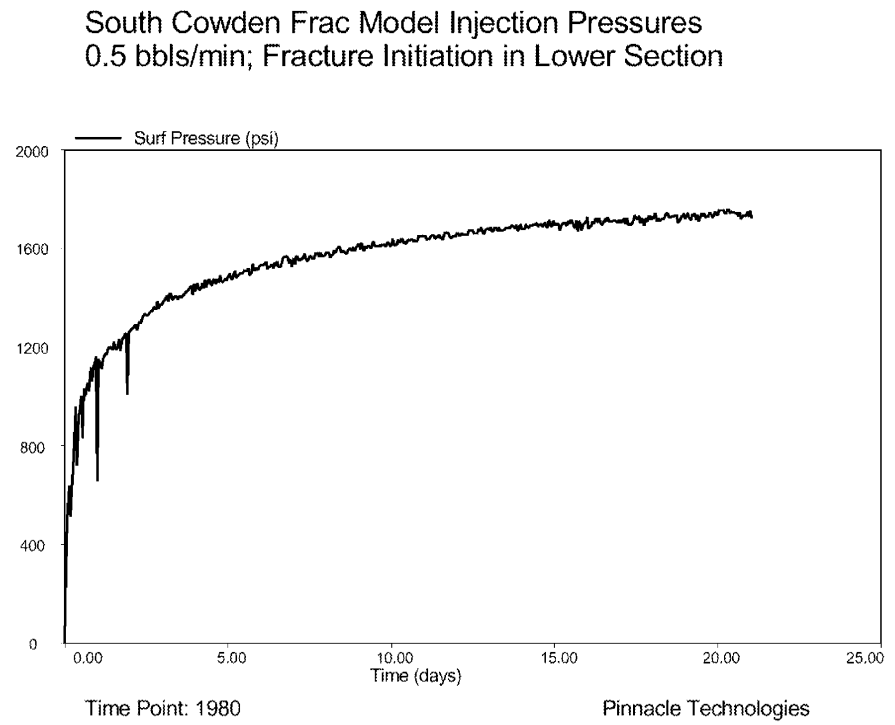

Figure 24. Model injection pressures for 1980: Initiation in lower section; Rate=24,000 bbls/mth

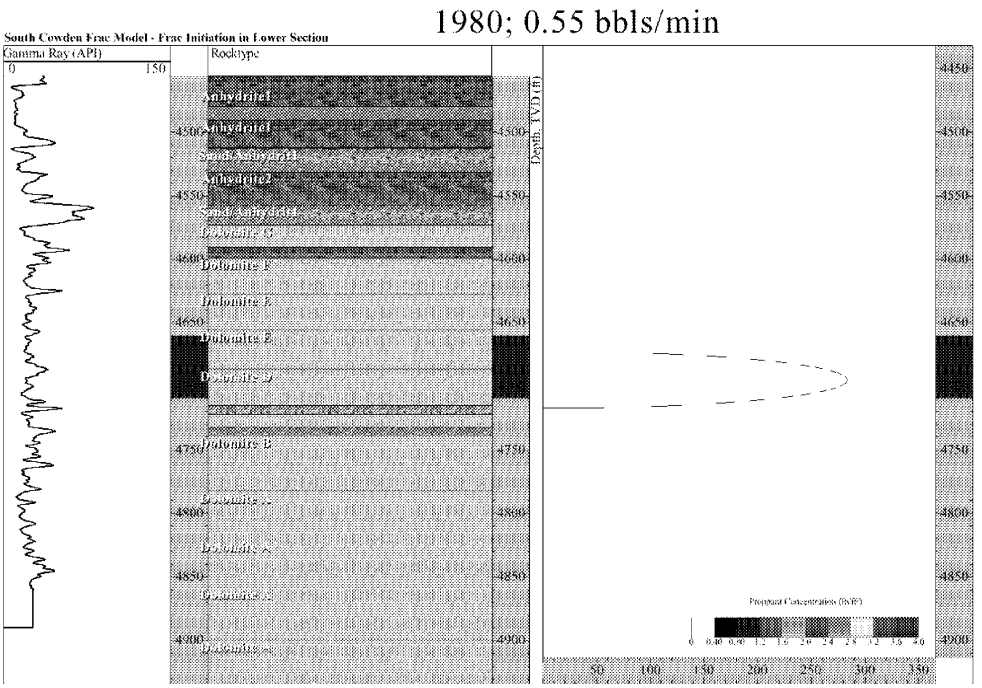

Figure 25. Model fracture geometry for 1980: Initiation in lower section; Rate=24,000 bbls/mth

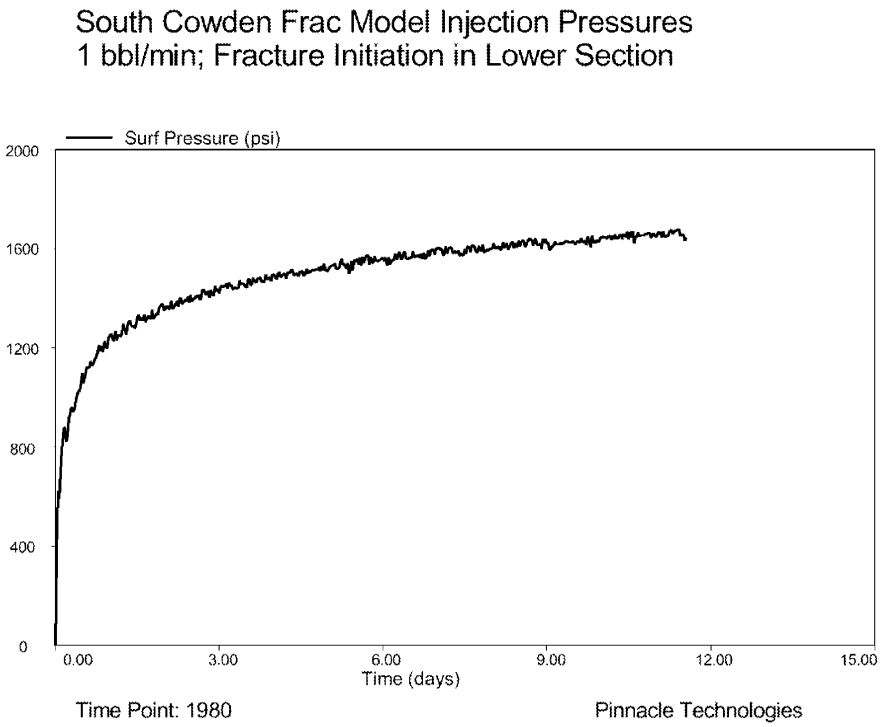

Figure 26. Model injection pressures for 1980: Initiation in lower section; Rate=44,000 bbls/mth

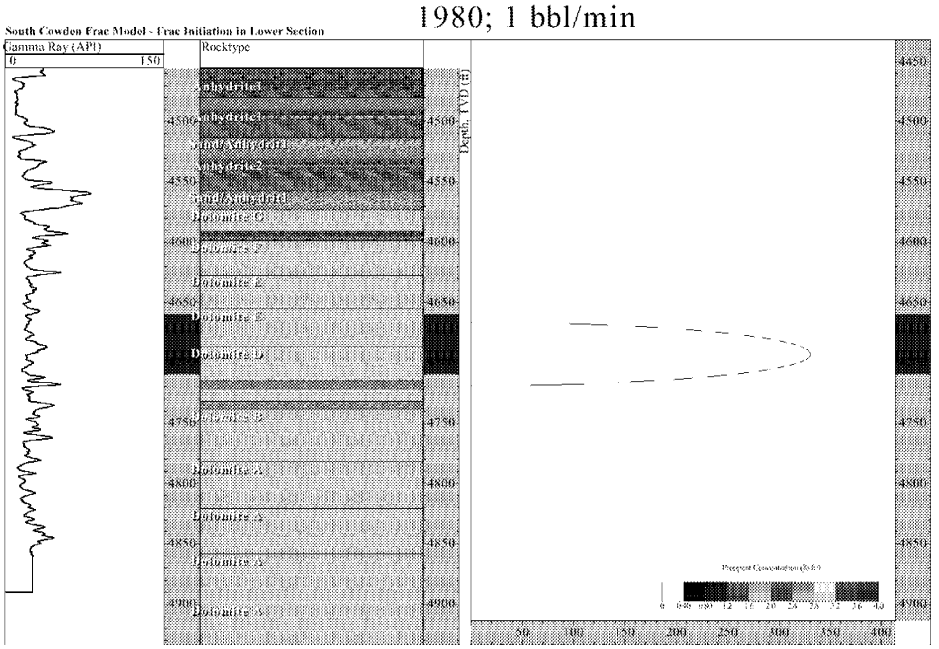

Figure 27. Model fracture geometry for 1980: Initiation in lower section; Rate=44,000 bbls/mth

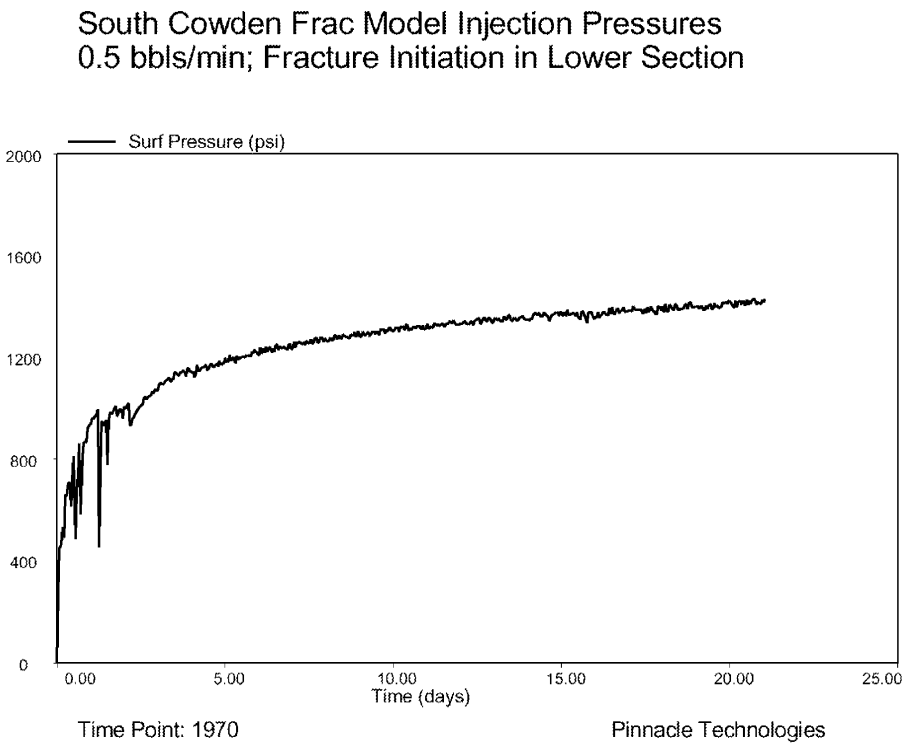

Figure 28. Model injection pressures for 1970: Initiation in lower section; Rate=24,000 bbls/mth

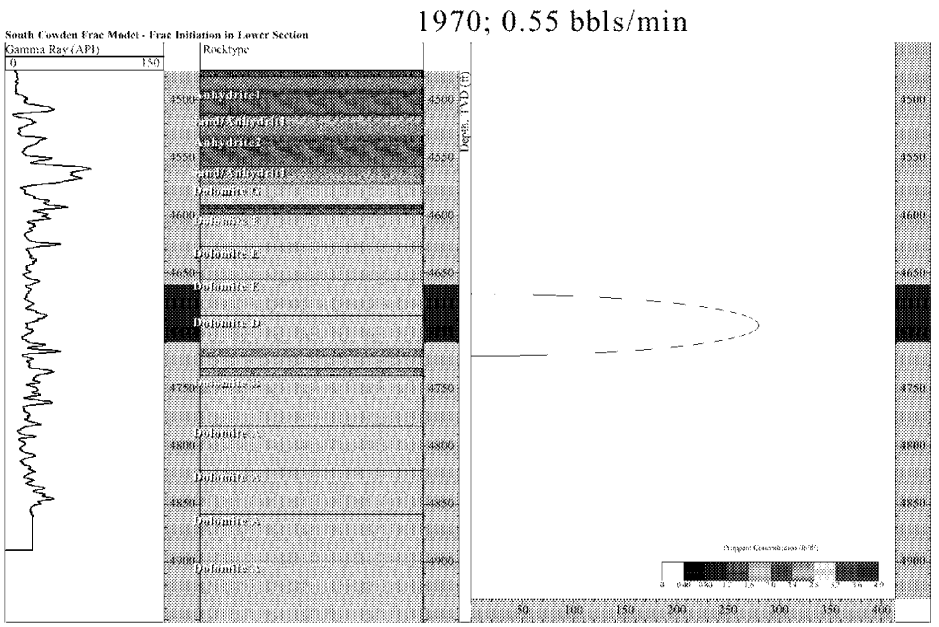

Figure 29. Model fracture geometry for 1970: Initiation in lower section; Rate=24,000 bbls/mth

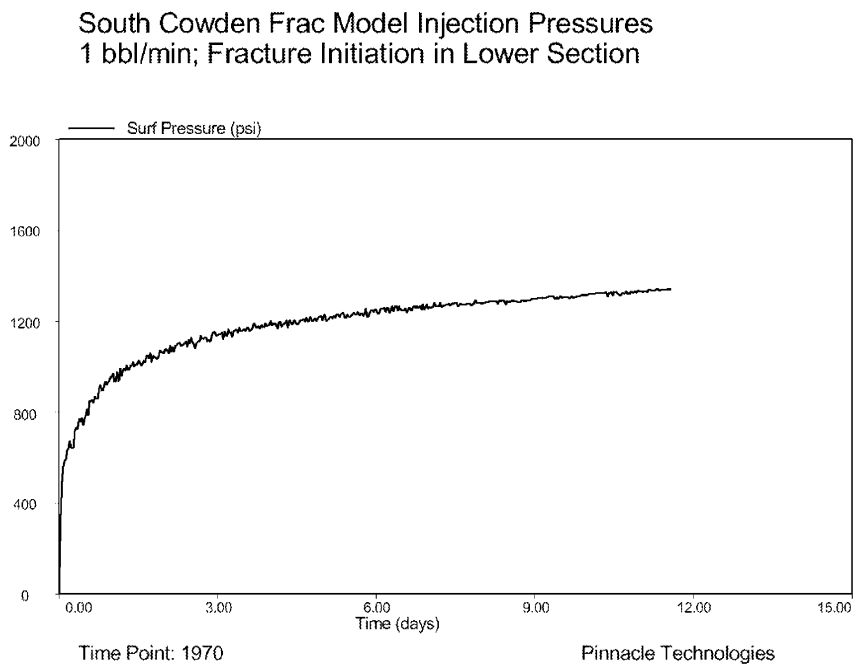

Figure 30. Model injection pressures for 1970: Initiation in lower section; Rate=44,000 bbls/mth

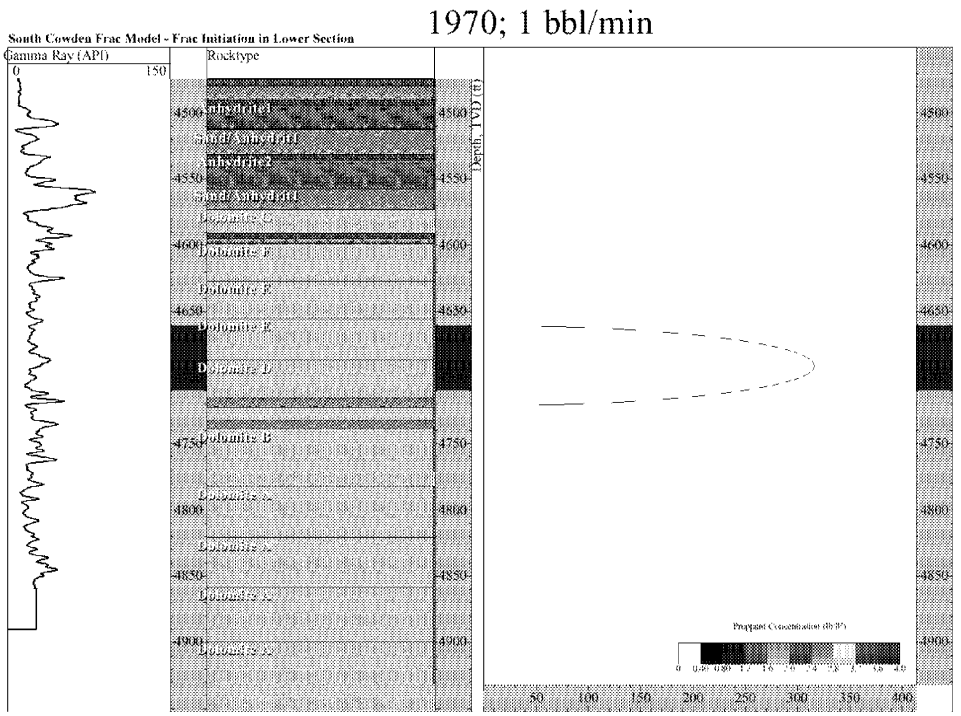

Figure 31. Model fracture geometry for 1970: Initiation in lower section; Rate=44,000 bbls/mth

2.2.3 Fracture Growth Patterns vs. Time

Figures 33 and 34 illustrate fracture growth versus time for initiation *below the E section* for the time period 1994-2000. **Figure 34** shows that the model predicts fracture breakthrough into the A & B zones after about 2.5 days, which corresponds to a sudden increase in lower fracture height (height below the middle of perforated interval).

Figures 35 and 36 illustrate fracture growth versus time for initiation *above the E section*. In this case the fracture reaches full height after about 12 hours. Afterwards fractures continue to grow only in length.

In both cases our modeling shows that within the time frame of acid treatments, fractures are fairly contained when pumped at 0.5 bbls/min (assuming no growth through cement channels or natural fractures).

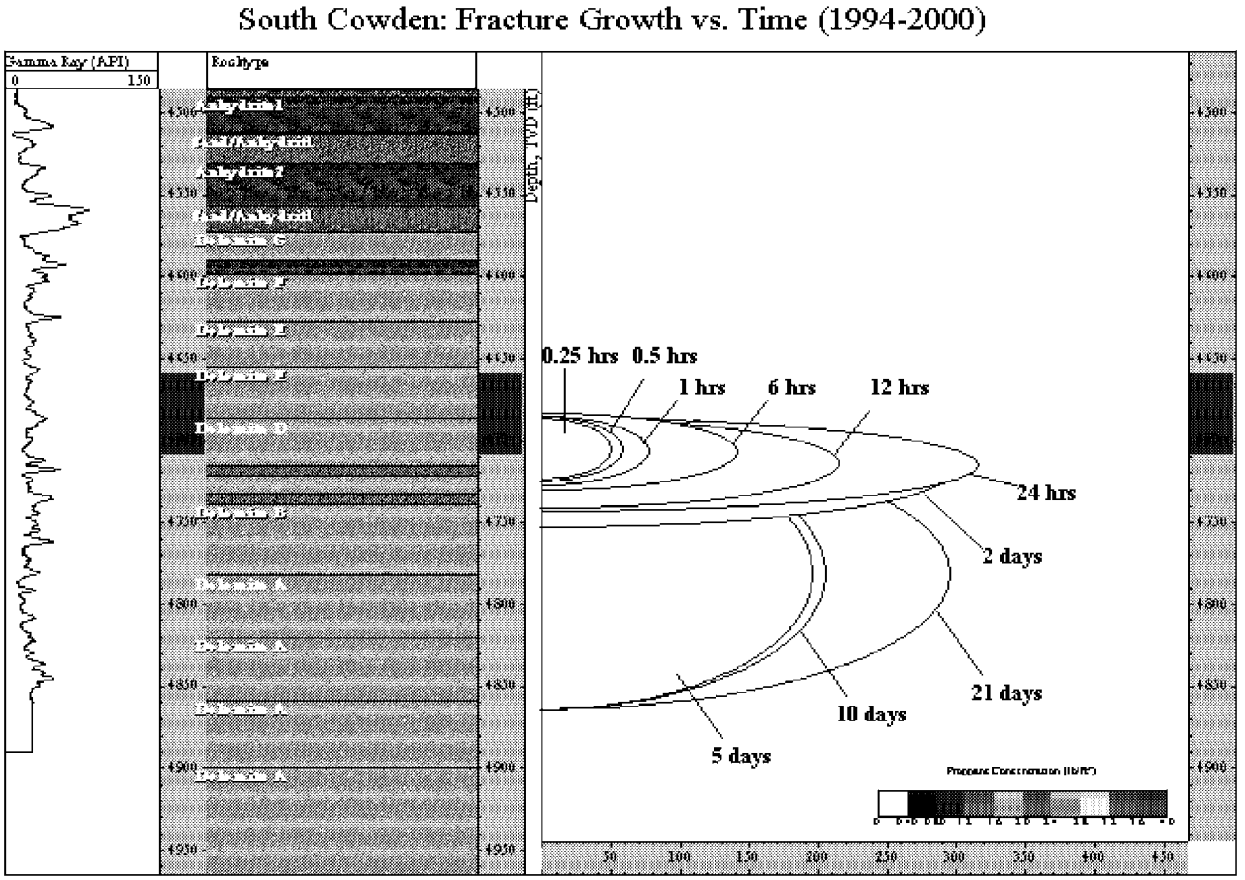

Figure 32. Model fracture growth vs. time: Initiation in lower section; Rate=24,000 bbls/mth

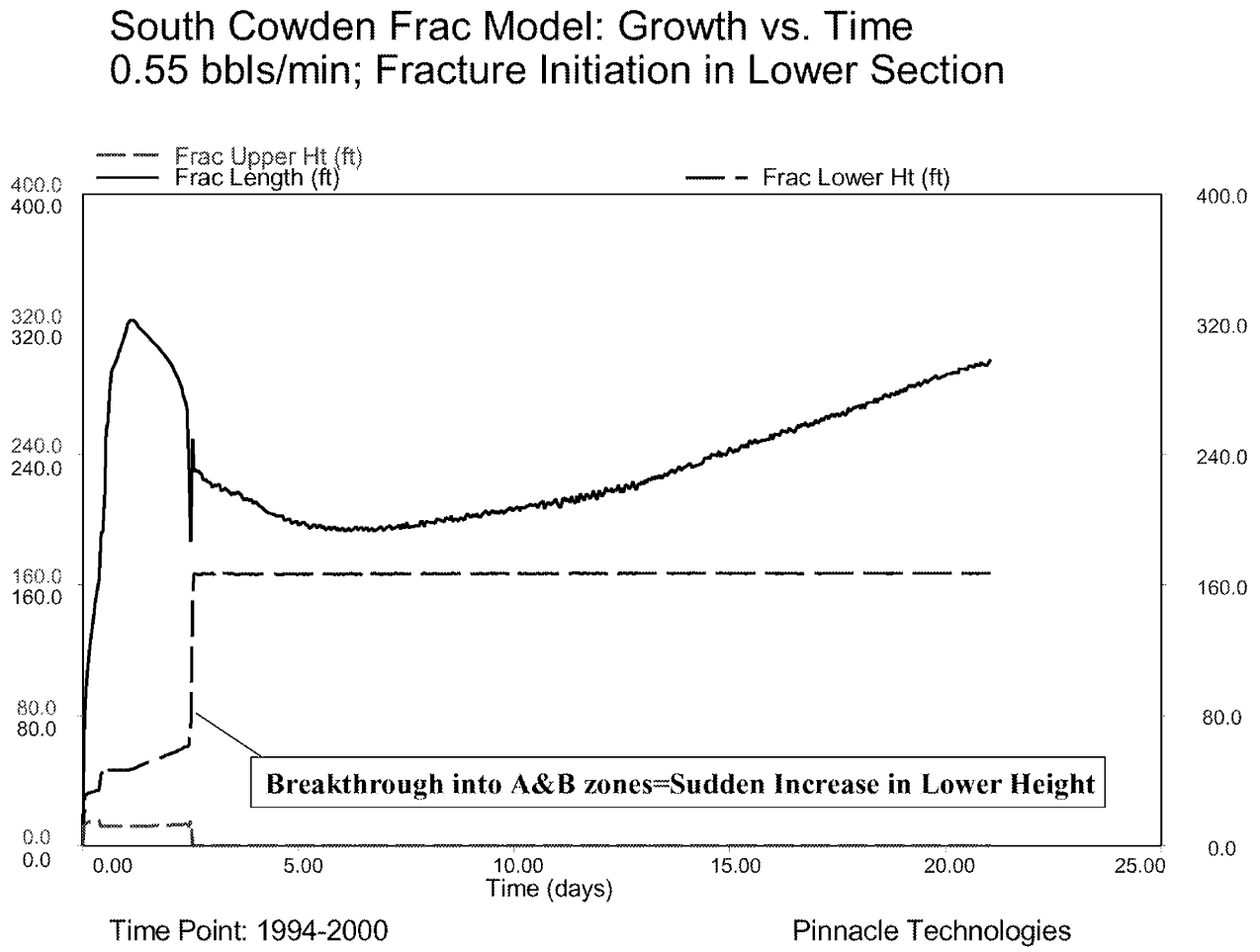

Figure 33. Model fracture growth vs. time: Initiation in lower section; Rate=24,000 bbls/mth

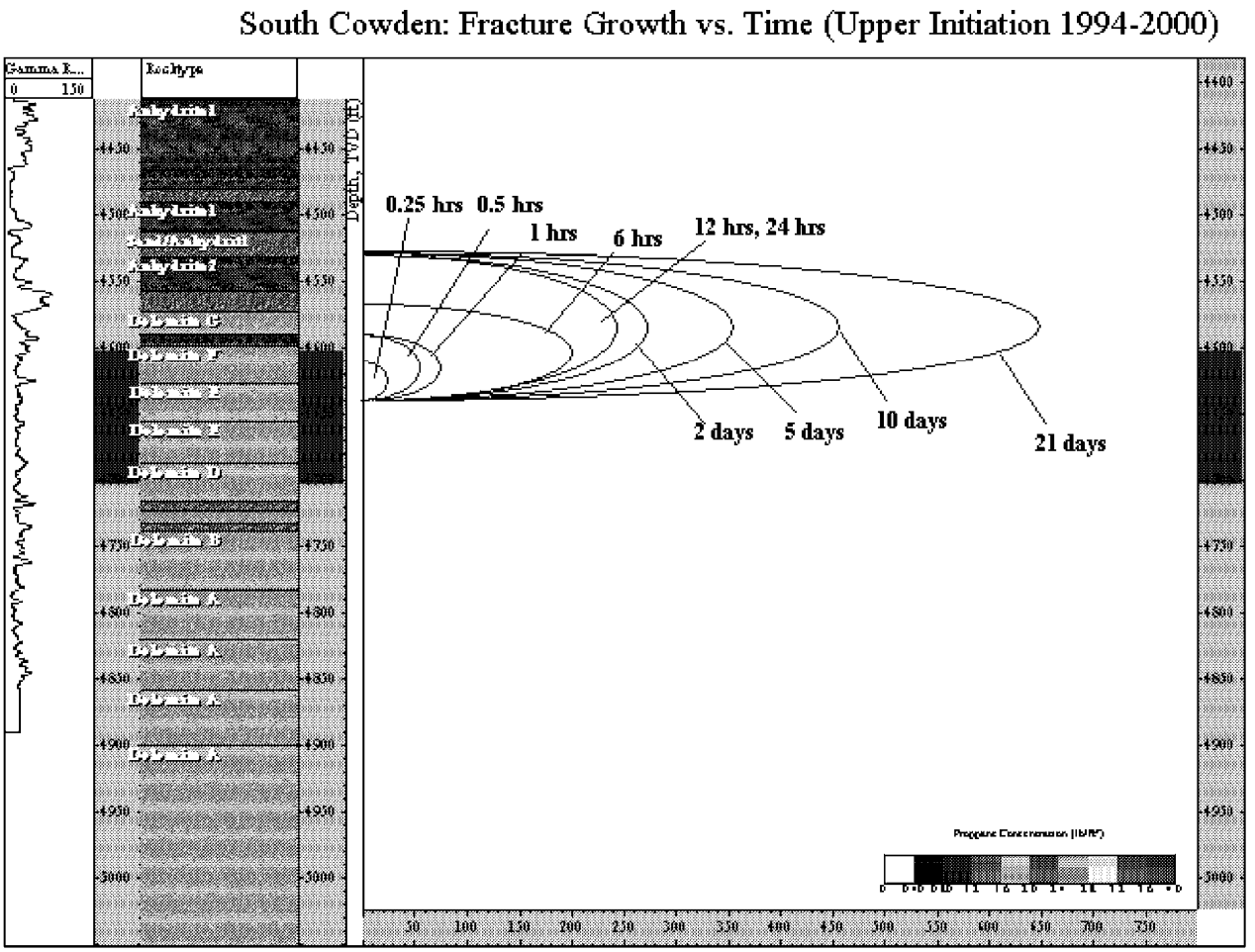

Figure 34. Model fracture growth vs. time: Initiation in upper section; Rate=24,000 bbls/mth

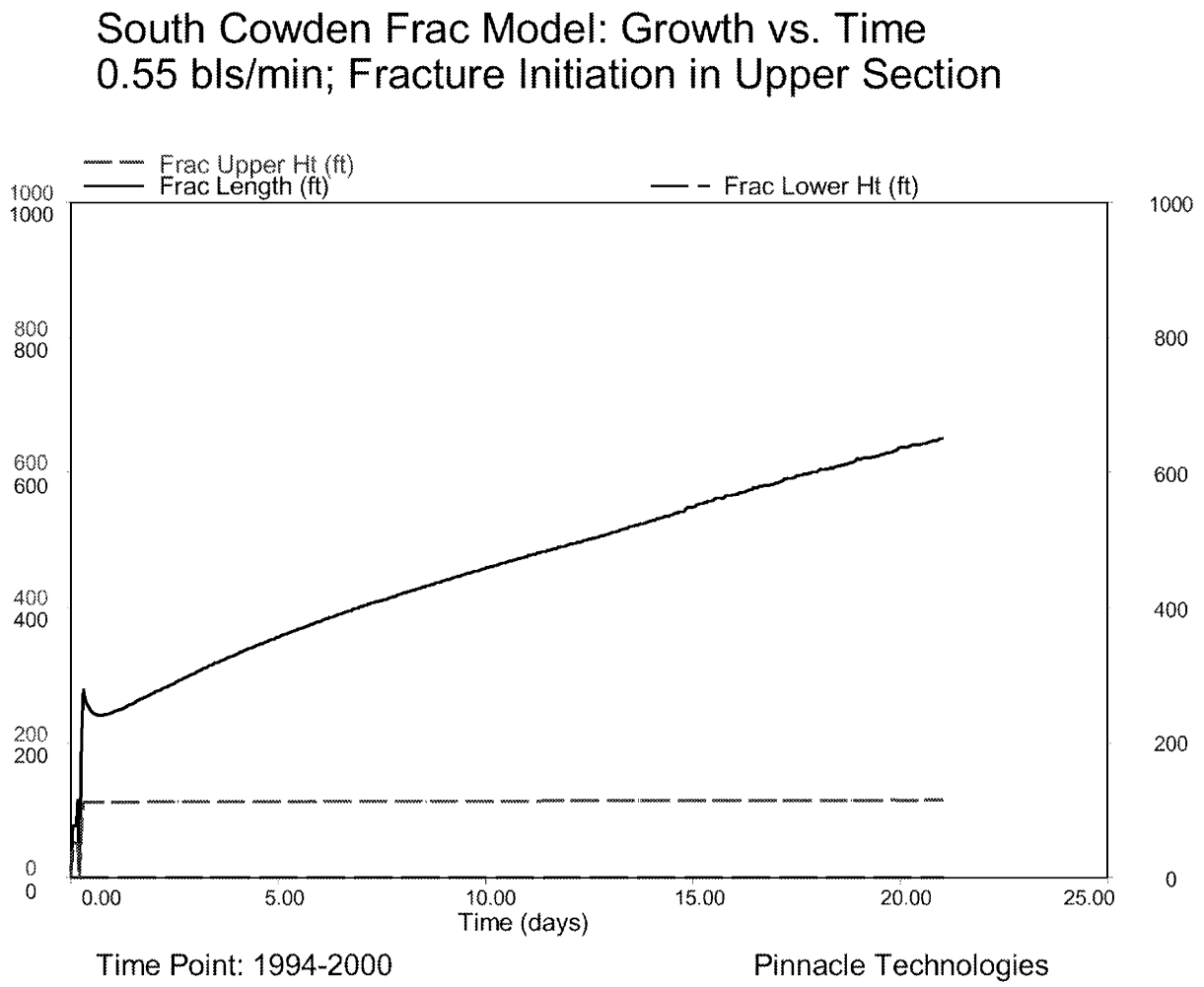

Figure 35. Model fracture growth vs. time: Initiation in lower section; Rate=24,000 bbls/mth

2.2.4 Small Volume Injections: Model Fracture Growth versus Injection Rate

The following simulations show potential fracture growth when injecting at higher rates up to 5 bbls/min (rates used in acid treatments).Modeling was done for 1, 2, 3, 4, and 5 bbls/min rates with 50 bbls and 100 bbls total injected volume. **Figure 37** illustrates model fracture growth versus injection rate for initiation *below the E section* for the time period 1994-2000. The graph shows the potential for some growth into the B section when injection rate exceeds 2 bbls/min. **Figure 38** shows model fracture growth versus injection rate for initiation*above the E section* for the time period 1994-2000. In this case the potential for significant upward fracture height growth can be observed when rates exceed 1 bbl/min.

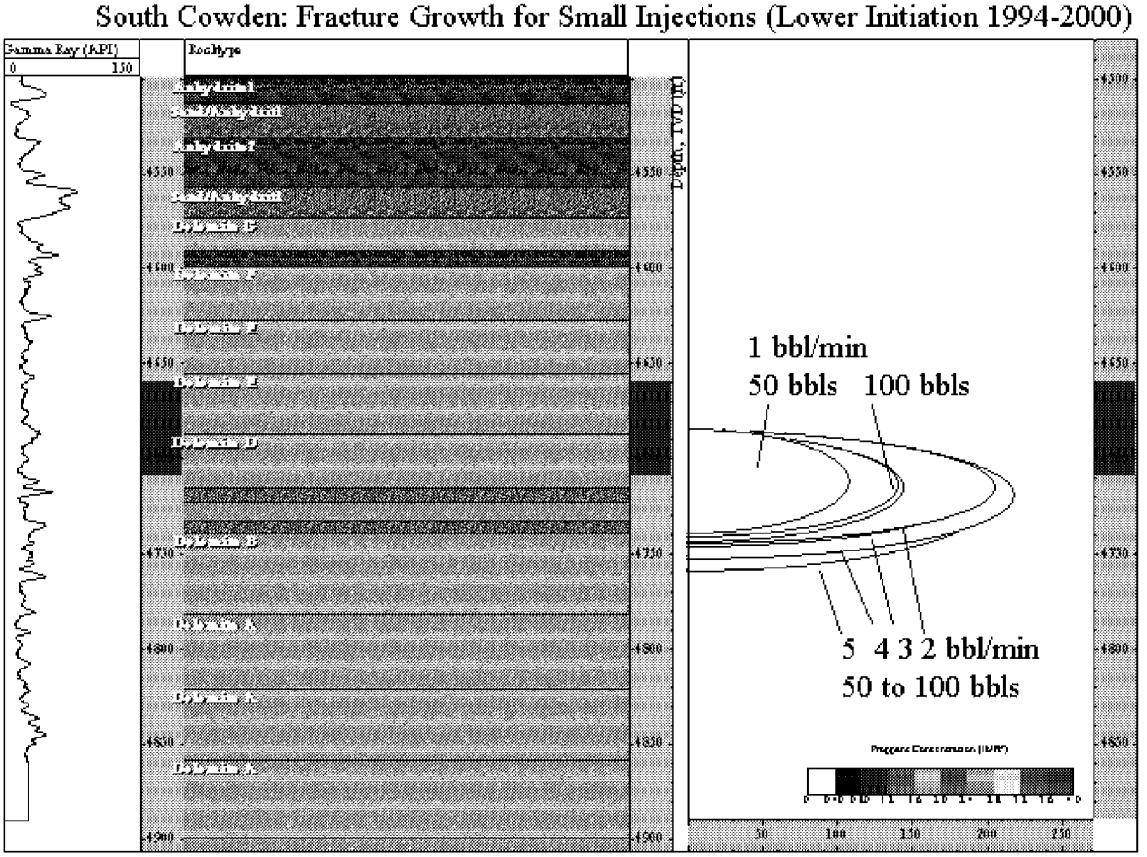

Figure 36. Small volume injections: Fracture growth vs. rate (Lower initiation 1994-2000)

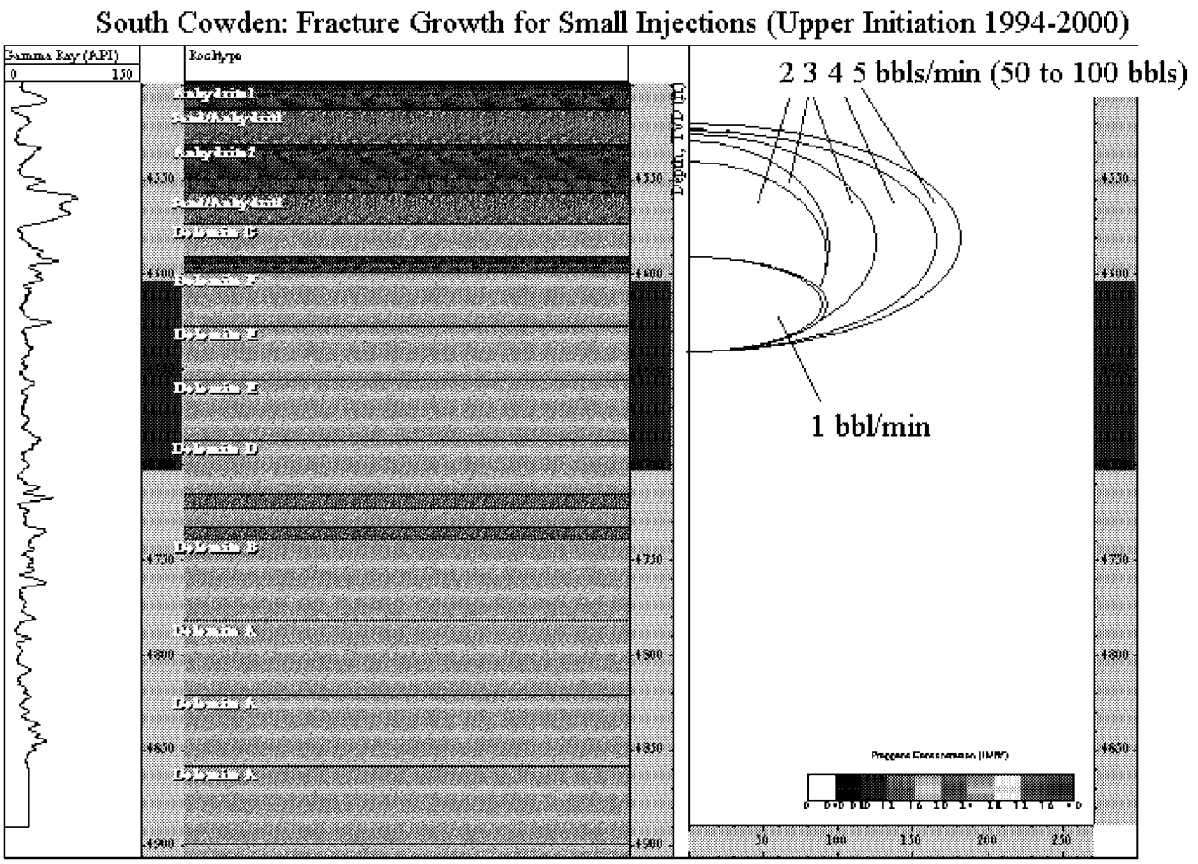

Figure 37. Small volume injections: Fracture growth vs. rate (Upper initiation 1994-2000)

Appendix– SPE Papers

#59525 – Identification and Implictions of Induced Hydraulic Fractures in Waterfloods
(Authors - Griffin, Wright, Demetrius, Blackburn, Price)

#59715 – Tiltmeter Hydraulic Fracture Mapping in the North Robertson Field, West Texas
(Authors – Mayerhofer, Demetrius, Griffen, Bezant, Nevans, Doublet)

APPENDIX G

Original Development and Redevelopment Review

Appendix G

SOUTH COWDEN CO_2 FLOOD PERFORMANCE REVIEW AND REDEVELOPMENT SUMMARY JANUARY 2000

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Appendix G

EXECUTIVE SUMMARY

The subject lease is currently under-performing its expected recovery under carbon dioxide (CO_2) injection. Injection commenced in the mid 1990s and monitoring of lease performances to-date suggest the under-performance is related to:

1) "Out of zone" CO_2 injection.
2) Through-wellbore communication of abandoned wells.
3) Productivity and injectivity of wells.

A redevelopment of South Cowden centered around short radius lateral drilling and selective stimulation in the upper San Andres was determined to be an optimum redevelopment scheme to improve the CO_2 flood. The optimum development with regard to recovery and economics follows a two-phased approach.

PHASE I – Test lateral technology, improve offtake in center of CO_2 flood.
PHASE II – Improve in zone injection and reduce reservoir pressure.

The phased approach will ensure short radius lateral drilling can be implemented effectively at South Cowden. This involves monitoring drilling operations and production response to determine if larger investments during the second phase are justified.

Capital required for redevelopment is estimated at $2.8MM gross, with incremental recovery estimated at 4.65 MMSTB above current CO_2 flood performance. Redevelopment operations are scheduled to commence in mid February 2000 with completion mid November 2000.

Appendix G

INTRODUCTION

Out Of Zone Injection

The San Andres intervals were split into 7 layers (A, B, C, D, E, F and G) as part of the reservoir characterization performed in the mid 1990's, as illustrated in Figure No. 1. The structure is tilted, so in some areas of South Cowden the majority of the San Andres is above the oil water contact (OWC) at –1800'Sub Sea, and in others below the contact. The CO_2 development team highlighted the need for injecting CO_2 in the upper layers, or the "in zone" section of the San Andres where layers are above the original oil water contact.

A summary of vertical and horizontal well CO_2 conformance observed during CO_2 flood implementation is summarized below. Refer to Figure No. 2 for CO_2 injector locations at South Cowden.

Vertical Wells

There are a total of 6 vertical CO_2 injection wells in the South Cowden Unit.

Wells	Area	Comments
2-26	Tract 2	CO_2 entering perforations (perfs) in C to G zones, but channeling to below B zone.
2-27	Tract 2	CO_2 entering perforations primarily in B and C zone, but channeling to below B zone.
6-24	Between Two Horiz Injectors, Tract 6.	Well currently a shut in producer with high CO_2 rates. Unknown conformance issues. The well will be converted to CO_2 injection at some future date.
6-26	Leaseline	CO_2 entering perfs in C zone, but channeling to below C zone.
6-27	Leaseline	CO_2 entering perfs in E zone, possibly a small channd below.
6-28	Leaseline	CO_2 entering perfs in D zone possibly channel below. Current lowest perfs need squeezing off (close to OWC). Well shut in since drilled.

Horizontal Wells

There are two horizontal injection wells in the South Cowden Unit.

6C25H	Tract 6	Well drilled in E zone at target depth of 4689'TVD. Well length drilled in E zone approximately 1900'. Well injecting as predicted and "in zone".

7C11H	Tract 7	Well drilled in E zone at target depth of 4672'TVD. Well length drilled in E zone approximately 1300'. Effective length of well taking CO_2 is 40'. Well injecting in "toe" of well, in some form of fracture plane, will require workover to resolve.

Overall, CO_2 conformance issues can be summarized as good in zone injection in well 6C25H, poor injection in well 7C11H– likely out of zone, poor injection in leaseline wells– majority out of zone, poor injection in Tract 2 - lower layer dominated.

Abandoned Well Communication

Eight wells at South Cowden are poorly abandoned. The abandoning method of placing a plug in casing above reservoir intervals has allowed communication paths to exist between reservoir intervals below the plug. Where known communication issues exist between all San Andres layers, any "in zone" CO_2 injection may be backflowing through abandoned wells to "out of zone" layers.

This is of major concern, most noticeably for South Cowden-Emmons leaseline wells, where new CO_2 injectors were drilled within a few feet of poorly abandoned wells.

Productivity/Injectivity

Productivity of wells is one of the major concerns for a successful South Cowden CO_2 flood. The majority of wells have not performed as anticipated due to combinations of:

a) Optimistic estimates of new well productivity.
b) Having ineffective methods to stimulate San Andres upper layers.

The effect of lower offtake rates on overall flood performance has been:

a) lower oil production
b) reservoir pressure 500 pounds per square inch (psi) higher than required
c) reduced CO_2 injection due to high reservoir pressure
d) Reduced throughput and CO_2 processing

Productivity can be improved through use of various non-fracturing stimulation techniques which will either reduce current wellbore skin factors, or can drill out away from current well locations, where skin damage and/or poorer quality rock exists. The two main techniques recommended for South Cowden are:

a) Short radius laterals
b) Stimgun perforating, followed by heated acid treatments

REDEVELOPMENT SCHEDULE/PLAN/COSTS

The major keys to redeveloping South Cowden are as follows:

1) Develop a method to improve productivity and injectivity without allowing communication to lower San Andres intervals.

2) Reduce overall reservoir pressure to improve CO_2 injectivity.

3) Developing methods to eliminate long term out of zone injection.

4) Ensure productivity can be maintained throughout the remainder of field life.

The overall strategy recommended to accomplish a successful redevelopment is primarily through the use of horizontal lateral drilling. The us of this technology will help improve productivity and injectivity through contacting better quality rock, contacting unswept areas and bypassing near well damage.

Several redevelopment options were considered for South Cowden. The optimum development with regard to recovery and economics follows a two-phased approach.

PHASE I – Test Lateral Technology, Improve Offtake in Center of CO_2 Flood.

Upgrade compressor to 4.5 MMSCF/D
Drill 4 laterals early 2000 – Wells 6-20, 6-22, 6-23 and 7-13
Monitor performance (decide to proceed with Phase II)

PHASE II – Improve In Zone Injection and Reduce Reservoir Pressure

Improve injectivity in zone.
Seal up wells 2-26, 2-27, 6-26, 6-27 and 6-28 in near well area and drill laterals.
Improve Tract 2 productivity in zone.
Test/Log/Stimtube/Hot Acid Wells 7-15, 7-12, 2-25, 2-24, 2-22, 2-21, 2-20, 2-17, 2-09, 2-08, 2-07 and 2-02.
Plug and Abandon (P&A) correctly 11 wells (some currently TA).
Relog Well 7C11H and resolve conformance.
Test Well 2-18D and upgrade to handle larger disposal rates.

The phased approach is used to ensure short radius lateral drilling can be implemented effectively at South Cowden. This involves monitoring drilling operations and production response to determine if larger investments during the second phase are justified.

Capital required for redevelopment is estimated at $2.8MM gross, with incremental recovery estimated at 4.65 MMSTB above current CO_2 flood performance. Redevelopment operations are scheduled to commence in mid February 2000 with completion mid November 2000.

Appendix G

Attachment A : Productivity Improvement

Several wells were drilled in the mid 1990's to replace mechanically unfit wells in the CO_2 flood area. Wells were also re-entered to increase offtake in specific areas of the CO_2 flood. One assumption used to generate Authority for Expenditure (AFE) forecasts was that new/re-entered wells would produce at similar offtake rates to original well rates seen during waterflooding. Figure A.1 highlights the areas of replacement/re-entered wells.

Original wells had various forms of completion, varying from open hole nitro-glycerine (nitro) stimulation to cased hole perforating followed by sand fracture stimulation. The degree of communication with water-wet lower San Andres intervals is therefore fairly uncertain. However, low water cuts seen during waterflood production history were thought to represent production emanating just from the upper oil-wet upper San Andres intervals, and would give a representative idea of upper San Andres productivity, in the area under pressure support.

6-22 Area

Wells 6-21 and 6-22 were drilled to replace production from wells 6-08, 6-13 and 6-04 in the area south of horizontal injector 6C25H. During waterflood start up in the late 1960s, offtake rates (refer to Figure A.2) increased to 600 barrels of fluid per day (bf/d) in both 6-08 and 6-04. Water cuts during this initial waterflood period prior to water breakthrough indicated well 6-04 probably had little communication with lower water wet zones (A and B zones in this well). Well 6-08, however, had consistently high water cuts indicating possible communication to lower zones. The well was hydromite treated in September 1971 to seal up all layers below the F zone.

Expected offtake rates from any well drilled in this area of the San Andres upper layers, under pressure support, would therefore be 600 bf/d. Wells 6-21 and 6-22, however, have not produced at this anticipated rate, Figure A.2.

Well 6-21 was initially perforated in the E zone and acidized in August 1994, then shut in until October 1994. A bridge plug was set above the E zone and the San Andres F/Grayburg zone perforated/acidized. The F/Grayburg was left on production until June 1997 when the bridge plug was retrieved. The upper layers of the San Andres were therefore not on full production until the second half of 1997, averaging between 25 and 75 bf/d. Offtake rates were improved in March 1998 with a scale squeeze which brought rates up to 80 to 100 bf/d, but still less than the expected 600 bf/d, Figure A.3.

Well 6-22 was also initially perforated and acidized in the E zone in December 1995 and immediately a bridge plug set above the E zone, Figure A.4. The San Andres F and G zones were perforated and acidized and the well placed on production with the bridge plug in place above the E zone. The bridge plug was pulled and all perforations acidized in August 1997. Offtake rates measured during late 1997 were 250 to 270 bf/d, which then dropped to under 50 bf/d in early 1998. A plug was re-set above the E interval in April 1998 because of safety concerns of high CO_2 rates in late 1997.

7-13 Area

Wells 7-13, 6-20 and 6-23 were drilled to replace production from wells 7-06 and 6-09 in the area north of horizontal injector 6C25H. Also, well 6-24 was drilled in between horizontal CO_2 injectors 7C11H and 6C25H. During waterflood start up in the late 1960s, offtake rates (refer to Figure A.5) increased to 150 to 250 bf/d at 6-09 and 7-06. Water cuts during this initial waterflood period, prior to water breakthrough, indicated 7-06 probably had little communication with lower water wet zones. Well 6-09, however, had consistently high water cuts indicating possible communication to lower zones.

Expected offtake rates from San Andres upper layers, under pressure support, would therefore be 150 bf/d. Wells 7-13, 6-20 and 6-23, have produced at rates less than 150 bf/d, Figure A.5.

Most noticeably, 7-13 drilled as an immediately offset to 7-06 produced under 100 bf/d since starting production, Figure A.6. An acid stimulation in mid 1997 did not improve offtake rates, nor did the lateral jetting undertaken in November 1998. Rates have never reached levels expected from the 7-06 analogy.

Well 6-23 drilled to offset 6-09 to the east, has produced at reasonable offtake rates, Figure A.7, apart from a period in late 1995 through early 1997 when rates dropped to under 5 bf/d. It is not known from well records what occurred during this period. Chemical and scale treatments appear to have helped maintain well productivity just under 100 bf/d since 1998.

Well 6-20 was reactivated in 1996. It has produced under 100 bf/d with the exception of a period in late 1998, Figure A.8. Scale and chemical treatments did not appear to improve offtake rates.

6-29 Area

Well 6-29 was drilled to replace production from well 6-01 in the area northeast of horizontal injector 6C25H. During waterflood start up in the late 1960s, offtake rates (refer to Figure A.9) increased to 300 bf/d at 6-01. Water cuts during this initial waterflood period prior to water breakthrough indicated 6-01 probably had little communication with lower water wet zones. Well 6-29 has produced fairly closely to the anticipated rate of 300 bf/d, Figure A.10.

Well 6-29 was initially perforated in theE zone and acidized in October 1997. The San Andres F zone was added and acidized in July 1998. The upper layers of the San Andres were therefore not on full production until the second half of 1998. Offtake rates were, however, approaching 300 bf/d in early 1998 just from the E zone, but rates have typically dropped to between 100 and 200 bf/d.

7-12 Area

Well 7-12 was drilled to replace production from well 8-14 in the area southeast of horizontal injector 7C11H. During waterflood start up in the early 1970s, offtake rates (refer to Figure A.11) were typically 250 to 300 bf/d at 8-14. Water cuts during this waterflood period prior to significant water breakthrough indicated 8-14 probably had little communication with lower water wet zones.

Expected offtake rates from San Andres upper layers, under pressure support, would therefore be 250 bf/d. Well 7-12 has produced fairly close to the anticipated rates, Figure A.12.

Well 7-12 was initially perforated in the E and F zones and acidized in November 1995. Offtake rates were typically under 10 bf/d until an acid stimulation in July 1997 improved rates to over 200 bf/d. A drop in productivity can be observed in late 1998, however, a scale squeeze improved rates in March 1999 to over 200 bf/d. Well 7-12, therefore, was able to produce at anticipated rates, and is one of the few wells observing a long-term improvement to offtake rate post acid stimulation and scale squeeze jobs.

7-02 Area

Wells 7-10 and 7-15 were drilled to improve production in the area northwest of horizontal injector 7C11H. Also wells 7-02 and 7-05 were re-entered to improve offtake to the west of 7C11H. During waterflood start up in the late 1960s, offtake rates (refer to Figure A.13) increased to 150 to 200 bf/d at 7-02 and 7-05. Water cuts during this initial waterflood period prior to water breakthrough indicated both wells probably had little communication with lower water wet zones.

Expected offtake rates from San Andres upper layers, under pressure support, would therefore be 150 to 200 bf/d. Wells 7-15 and 7-02 produced at rates less than 150 bf/d, Figure A.13. The re-entered well 7-05 has produced at over 200 bf/d while 7-10 has produced at approximately the expected rate.

Well 7-02, originally drilled in 1948, was completed open hole with acid stimulation in the San Andres E, F and G zones, Figure A.14. The well was sand fracture stimulated in March 1972; increasing offtake rates over 200 bf/d including increased water production suggesting the fracture stimulation tapped into some lower water wet San Andres intervals. Prior to the fracture stimulation offtake rates were 150 bf/d suggesting this level of productivity for the upper San Andres maybe more realistic for non-fracture stimulated wells in this area. The well was temporarily abandoned (TA'd) in 1993 and re-entered in 1996. Various chemical/scale treatments or acid stimulation have not improved productivity dramatically during 1997 and 1998. The well was shut in during late 1998 and placed back on production in June 1999. Recent rates during the last few months in 1999, not shown on Figure A.14, have dropped below 50 bf/d.

Well 7-05, originally drilled in 1948, was completed open hole with acid stimulation in the San Andres E, F and G zones, Figure A.15. An acid stimulation in May 1973 seemed to improve offtake rates without severe water rate increases. Water broke through a year later. The well typically produced 150 to 200 bf/d from the upper layers of the San Andres. The well was TA'd in January 1994, and re-entered in September 1996. Offtake rates appeared to improve with an acid stimulation in June 97. The well has exceeded productivity expectation throughout late 1997 and 1998 and is currently still averaging over 150 bf/d.

Of note for both 7-02 and 7-05 is productivity loss from 1984 through to 1993. During this period there was no loss in injectivity from surrounding injection wells, Figures A.16 and A.17. During this time period there were no stimulations or treatments to improve productivity, suggesting the productivity loss from 1984 to 1993 was related to near wellbore skin damage.

Well 7-10 was drilled in 1993, perforated and tested in lower San Andres, which were subsequently isolated. The E zone was then perforated and acidized and put on production for two months in 1993 prior to being TA'd, Figure A.18. The well was re -entered in December 1996 and produced from the E zone. Typically the well averaged just over 100 bf/d. The well was shut in late 1998 and placed back on production in June 1999.

Well 7-15 was drilled in 1996, perforated and acidized from the C to F zones. The well typically averaged between 50 and 100 bf/d even after chemical and scale treatments, Figure A.19.

A summary, Figure A.20, contains a comparison of upper San Andres productivity with the expected productivity based on early waterflood history. Actual offtake rates are 1330 bf/d, or 48%, less than expected. The majority of wells performed less than expected, with wells 7-12 and 7-05 the only two wells having better performance.

Figure A.20 contains the forecasted offtake rates from the original AFE simulation model. Actual offtake rates are 660 bf/d, or 33%, less than expected. The majority of wells performed less than expected, with 7-12, 7-05 and 6-22 the three wells having better performance. Referring to Figure A.20, the original simulation model was actually taking a pessimistic view on productivity for some wells. For example, wells 6-21 and 6-22 were expected to produce at rates of 150 bf/d. Early waterflood history could justify expecting 600 bf/d. Other wells, such as 7-13, 6-23, 7-05 and 7-15, were expected to produce at rates of 100 to 140 bf/d higher than observed during early waterflood history.

When comparing with *simulation* predictions, the wells with the worst under-performance are 7-13, 7-15, 7-02 and 6-23. Similarly, when comparing with *early waterflood* history, the wells with the worst under-performance are 6-21, 6-22, 6-29 and 7-13. Apart from 6-21, all these wells have had various forms of productivity improvement attempted (acid stimulation, chemical/scale treatments, lateral jetting and scale squeezes) but no technique has been successful in obtaining expected rates.

Figure A.21 summarizes the effect productivity loss has had on expected oil production. Current oil cut/liquid offtake rate, as measured in June 1999, for each well and potential rate from the original simulation modelling are shown. Wells 6-22, 7-13, 6-23 and 6-20 are where the greatest short fall in expected oil production lie. Overall approximately 200 barrels of oil per day (bo/d) lower oil production can be explained by lack in productivity.

The question that needs to be addressed is whether productivity assumptions used for the Authority for Expenditure (AFE) generation are still valid today.If this is so, then whether some form of stimulation can be performed to improve well productivity back to original premises.

Completion Practices

Figure A.22 summarizes various forms of initial completion for 1940 and 1950 wells in the five areas and compares offtake rates with modern completion practices (for periods in the CO_2 flood where upper San Andres intervals were producing). The figure suggests wells nitro-glycerine (nitro) shot tended to have better productivity than replacement wells. For example 6-04 drilled and nitro shot in 1949, averaged 600 bf/d during the early waterflood. Yet a well such as 6-21 or

6-22 drilled, perforated and acidized in the mid 1990's averaged 100 to 250 bf/d. Similarly 6 -01 drilled and nitro shot in 1948 averaged 300 bf/d, whereas 6-29 has averaged 150 bf/d.

Caliper logs run in wells after having nitroglycerine stimulation are summarized in Figure A.23. Although the processes involved in nitro stimulation are somewhat uncertain there are probably two beneficial effects, if considering just upper San Andres intervals. The first is wellbore radius increase and the second reduction in skin factor due to micro fracturing in the near well area. Figure A.24 illustrates how, under steady state conditions, a modern perforated/acidized well with skin factor of –1 and wellbore radius of 4.75", compares to an older well with variances in wellbore radius and skin factor caused by nitroglycerine shooting.

Although probably not the only reason for lower than anticipated productivity, 1940's and 1950's nitro shot wells had very effective completion practices if they could maintain withdrawal just from the upper, oil rich, San Andres intervals. It also suggests it would be invalid to assume modern completion practices used to date at South Cowden should be expected to produce at similar offtake rates to original wellbores.

Reservoir Quality

Figures A.25 through A.33 illustrate how reservoir rock quality compares to predicted values from simulation expectations. The simulation model E zone was split into 4 layers, to model heterogeneity, fluid gravity segregation, placement of horizontal wells, and to allow history matching through use of Kv/Kh ratio.

Porosity-permeability correlations for major rock types were used during reservoir characterization to determine layer permeability. Simulation layer porosity can therefore be used to compare with neutron-density log results to determine whether predicted reservoir properties for new wells were pessimistic or optimistic.

Figure A.34 summarizes a comparison of actual porosity/offtake rates with AFE simulation predictions. Where optimistic expectations of offtake rates were expected there does appear to be lower actual quality rock.

This, however, does not explain productivity lacking inwells 6-22, 6-23 and 7-12 where lower offtake rates cannot be explained by poor quality rock.

Reservoir Pressure

Another possibility for lack of productivity could be lower reservoir pressure. However, several downhole tests and repeat formation tester (RFT) measurements of layer pressures during the mid 1990's suggest lack of reservoir pressure is not a concern at South Cowden. Typical measurements were around 2300 pounds per square inch absolute (psia), optimum reservoir pressure for the CO_2 flood is 1800 psia.

Voidage replacement is shown in Figure A.35 for South Cowden wells shown in Figure A.36. Total downhole injection (CO_2 and H_2O) has exceeded offtake (oil, CO_2, and water production) at downhole conditions for the majority of flood duration from mid 1996. Typically, the ratio of injection to offtake, varying between 1.45 and 1.15, indicates reservoir pressure increasing during

this period. Drilling of disposal well 2-18D in late 1998 and also cutting back on CO_2 purchase volumes has helped reduce voidage and reservoir pressure.

Figure A.35 indicates the effect of low productivity at the lease. A viscous spiral of lack of productivity causing offtake not able to match injection rates, reservoir pressure increase, lower injectivity, reduction in throughput and CO_2 rock processing reducing. If the project is to improve it must be able to break this spiral by improving offtake rates to lower voidage/reservoir pressure and improve processing.

Methods historically attempted to improve productivity are discussed below, followed by newer technologies currently available, but as yet untested at South Cowden.

Acid Stimulation 1996 and 1997

During 1996 and 1997 22 wells were acid stimulated to improve withdrawal rates from South Cowden. Figures A.37 to A.58 illustrate individual well performance post-acid stimulation. Figure A.59 summarizes the acid stimulation results. Figure A.60 shows a map of stimulated wells.

The majority of wells have shown some production increase. For 22 wells, the average duration where offtake rates were greater than rate prior to acid treatment was 7.2 months. Three wells, 7-12, 7-15 and 8-02 appeared to have the best response to acid treatment, averaging over two years where rates were better than pre-acid. If these three wells are removed from the statistics the average duration where rates are greater than pre-acid rates is 4 months.

Wells were also assigned a target rate for the acid stimulation to achieve. The average duration where offtake rates were greater than target was 3 to 4 months.

Although acid treatments appeared to have improved rates they have not achieved long-term productivity improvements for the majority of wells. The acid treatments typically cost $21,000. To maintain productivity with the same acid stimulation techniques used on the 21 wells in 1996 and 1997 would require an additional $1.76MM/yr operating expense, if stimulations occurred every 3 months. Obviously this has a severe impact on project economics and alternative methods must be developed to improve long-term productivity.

Mini Frac and Acid Laboratory Tests

Mini frac tests performed on wells 6-21 and 6-23 in mid 1994 revealed fractures tend to grow downward into the lower layers of the San Andres once fracture initiation pressure is reached. Well 6-23 was tested with the entire San Andres interval open hole. This revealed preferential fracture initiation in the A zone which grew up to the D zone. Fracture initiation started at 2608 pounds per square inch gauged (psig) at 4742'. Well 6 -21 was tested open hole just in the E zone, prior to drilling into lower layers. The logging revealed a fracture initiated in the E zone at 2717 psig downhole pressure (at 4684') would grow downward to lower intervals.

Acid stimulation performed above fracture pressure will therefore allow communication to the majority of intervals in the San Andres even if perforations are contained in upper layers.

Core permeabilities from various wells have highlighted lower San Andres intervals have better permeability than upper layers in the majority of the field. Any acid stimulation, where treatment pressures exceed fracture initiation pressure, will therefore open up communication paths to higher permeability, lower San Andres intervals and preferentially inject acid intothe high permeability lower layers.

In addition, core samples from 6-24, from various zones in the San Andres, were recently tested for acid solubility and reaction time at various temperatures, Figure A.61. The results suggested carbonate intervals with high anhydrite content (lower permeability– upper layers) have slow reaction times when compared to low anhydrite carbonates (high permeability– lower layers).

For example, the lower layer C zone has measured core permeability of 831 millidarcies (mD) with slight anhydrite content. Over a 15-minute period, dissolved in 15% hydrochloric acid (HCl), the sample lost 95% of its original weight. The target E zone has a permeability of 6 mD at 4697'and lost 54% of its original weight. Higher up in the E zone at 4678'permeability is 1.4 mD and the sample lost only 26% of its original weight. In the G zone where anhydrite content is high, permeability is 0.01 mD and the sample barely reacted with the acid, losing only 7.6% of it original weight.

(*Note: also the barrier between the C and D zone, a dolomitic sandstone, which is one of the really extensive permeability barriers preventing vertical communication to lower zones, had very poor reaction to acid).*

Consequently these facts may explain poor results obtained from acid stimulations during 1996 and 1997. It is likely the majority of stimulant entered lower layers, through communication paths opened up when treatment pressures went above fracture initiation pressure. Rather than stimulating the zones of interest in the upper layers, the acid was preferentially diverted and reacted with lower layers.

Production test data for 5 wells are presented in Figures A.62 to A.66. This data has finer detail of well performances post acid treatment when compared to monthly-allocated data presented in Figures A.37 to A.58. Wells are generally tested two to three days after the acid treatment, so the majority of flush production, 100-120 barrels, has already backflowed.

Well 2-01 was acid treated at 2600-psi surface pressure or 1950 psi higher than fracture initiation pressure. Offtake rates post test are 140% greater than pre-acid rates suggesting the treatment may indeed have opened up communication paths with additional intervals. Longer-term offtake rates reduce and stabilize, suggesting the communication paths seal up. Similar responses are illustrated in Figures A.64 to A.66.

Well 2-08, Figure A.63, illustrates the expected performance for acid treatments, where rates have stabilized after the treatment at about 50% greater offtake rate.

Lateral Jetting

Another method of improving productivity emerged during 1998. New technology to create lateral boreholes in existing wellbores using coiled tubing and jetting technology was developed. Three producing wells (1-07, 6-23 and 7-13) were jetted during October 1998. Productivity

improvements from these wells were closely monitored. The technology is still under evaluation and we await improvements from the companies developing the technology before it is used on other wells.

Productivity Improvement Technologies

Any stimulation technique to be used at South Cowden would ideally have the following characteristics.

Selectively improve offtake only from upper San Andres intervals.
Does not require stimulation above fracture initiation pressure, or cause fracturing downward to lower layers.
Intercept reservoir rock away from wellbore
Cost effective
Provide a long-term productivity solution.

The technologies identified that have these characteristics are summarized in Figure A.67 and discussed below.

Stimgun

This technique is a deep penetrating re-perforating technique causing high pressure gas into the formation initiating micro fracturing in the perforated interval, Figure A.68. Even though high pressure stimulation is involved, duration is short and the technique only causes stimulation in the near wellbore area immediately adjacent the perforated section.

Typical cost per well is estimated at $30k.
Typical depth penetrated from wellbore 4 to 6 feet.

Lanced Perforating

This technology was attempted at South Cowden in well 6-23 in February 1995. The San Andres F zone had 4 lanced perforated sections, each extending approximately 10'into the formation. The production history from 6-23 does not show a significant improvement after using this technique. It is now believed the company has improved the technique enough to consider using it at South Cowden.

The technique involves milling out a circular hole in the casing followed by jetting at high pressure through a lance that extends into the rock. The jetted hole is 0.8 to 2 inches in diameter, Figure A.69.

Typical cost per well is estimated at $7k, escalated to 2000 prices.
Typical depth penetrated from wellbore 8 to 10 feet.

Acid Treatments

Although acid stimulation did not improve offtake rates in the majority of wells it has improved some wells. If acid stimulation is used in conjunction with other forms of stimulation it may help

clean up wells and improve offtake. For example, a stimgun technique followed by an acid stimulation, below fracture pressure, maybe an effective way to restimulate wells. If acid is also heated at surface it would help reaction with upper San Andres layers, as summarized in Figure A.61.

Typical cost of a heated acid treatment is $10k per well.

Jetting

This technique jets out fluids at high pressure through a nozzle gradually fed through a connection to a flexible hose, which extends through a small diameter coiled tubing to pump at surface, Figure A.70. If the technique works a lateral 4"to 4.5"in diameter is created out 200 to 300 feet. The technique was tried in three wells at South Cowden but no long term productivity has been observed. The advantages of this technology are its low costs and being able to intercept reservoir rock out from the wellbore. The companies marketing this technique must demonstrate they have proven technology before further wells are attempted.

Another company has developed a similar technique but using coiled tubing throughout, instead of a flexible hose. The difficulty with using coiled tubing, as opposed to a hose, was developing an ultra short radius whipstock and tubing materials that withstand the buckling forces as the coil is turned through 90 degrees into the formation. Their equipment was developed from US Navy technology and has a proven track record in various fields. Currently their technique could not be used at South Cowden, as a 5.5"casing or greater is needed to use the system. The majority of South Cowden wells have 4.5" casing. Phillips would need to help the company with development costs to use the system in smaller size casing.

Both the jetting techniques are currently not recommended for South Cowden. The companies developing the techniques will be monitored until the techniques become viable.

Short Radius Lateral

The technique involves milling out a section of casing, sealing up all layers with cement and drilling out any number of lateral sections at various depths. Figures A.71 and A.72 illustrate well configurations prior to drilling for a cased and an open hole well. Figures A.73 to A.78 illustrate several alternative lateral techniques that can be employed in both cased and open hole wells.

Phillips has discussed at some length the risks involved with lateral configuration proposed at South Cowden. The company felt the proposed work is a perfect application for short radius laterals and is well within their comfort zone from a mechanical perspective.

ATTACHMENT B : Conformance History

South Cowden and Emmons Units have used several methods to resolve out of zone injection during waterflood history. At Emmons, Fina used mainly polymer gel technology. A review of the more recent methods using foamed cement at South Cowden is discussed below.

Appendix G

Three leaseline wells 6-26, 6-27 and 6-28 had foamed cement treatments during 1997.

6-26

Well 6-26 was completed with perforations in the C, D, E, F zones in December 1996. A subsequent injection log, after injection commenced in February 1997, revealed a cement squeeze was required to prevent behind pipe communication from Grayburg water wet sand 300 feet above the San Andres. The log also revealed a small behind pipe channel below the C zone to the water leg in the B zone. Generally the profile suggested a fairly uniform distribution of injectant over the upper San Andres interval. The injection log was run at 850-psi surface injection pressure and 340 barrels of water injected per day (bwi/d). This is approximately 200 psig above the estimated fracture initiation pressure. Typically the well injected at 700 to 800 psi through the early part of 1997.

Both the C zone and the upper F zone where conventionally cement squeezed off to prevent behind pipe communication in April 1997. A subsequent injection profile, in May 1997, revealed the upper squeeze in the F zone was successful in isolating the Grayburg water production, but the lower squeeze had not isolated lower zone behind pipe communication. The profile revealed out of zone injection had worsened since the February logging. 94% of injectant entered the lower E zone perforations but temperature logs indicated a behind pipe channel to lower zones. The porosity logs indicated E upper layers had the largest porosity, where the injectant was meant to be moving into. It was decided to use foamed cement to squeeze the entire remaining perforations in June 1997 and reperforate/acidize the upper E interval.

A subsequent injection profile, in July 1997, revealed the technique was not successful in isolating the out of zone injection. The log indicated 100% of the injectant entering the D zone and below, in perforations intended to be squeezed off. None of the injectant entered the re-perforated upper E interval where there is excellent porosity.

The acid treatment after the upper E zone re-perforating was used as the reason for the unsuccessful foamed cement squeeze. Treatment pressures where typically 1100 psi. This may have caused behind pipe communication and opened up previously squeezed intervals.

Well 6-26 highlights the problem of being able to re-stimulate zones after a potentially successful conformance technique. In order to achieve expected acid injection rates in the upper E zone surface pressures greater than 500 psi were required at surface.

Well 6-26 injected at 400 to 1000 MSCF/D CO_2 at 1100 to 1350 psi from July 1997 to mid 1998. This is slightly above the recommended maximum injection pressure of 1150 psi. Currently the well is injecting only 250 MSCF/D.

The well was originally drilled 97 feet away from abandoned well 6-15. Well 6-15 was a leaseline water injector up to August 1997. The last injection survey in December 1983 was after a polymer treatment. The log indicated a communication conduit existed in 6-15 to all layers in the San Andres (the polymer treatment was not successful). The well was then P&A'd with cement plugs above the San Andres reservoir interval, so a communication conduit potentially still exists.

6-27

Well 6-27 was completed with perforations in the A, B, C, D, E, and F zones in January 1997. A subsequent injection log after injection commenced in February 1997 revealed a cement squeeze was required to prevent injectant entering the A zone. Foamed cement was used to squeeze off the entire perforations in August 1997 and the E zone was reperforated and acidized.

A subsequent injection profile, in September 1997, revealed the technique was unsuccessful in isolating the majority out of zone injection. The log indicated 100% of the injectant entering the E zone. The temperature log indicated departure at the base of the E zone, suggesting the majority of the behind pipe communication was sealed, with maybe a small proportion communicating below the E zone. The log could not run below the E zone to confirm, as a bridge plug was placed below the E zone.

Well 6-27 had been injecting at 150 to 1000 MSCF/D CO_2 at injection pressures of 1250 to 1360 psi from July 1997 to end of 1997. This is slightly above the recommended maximum injection pressure of 1150 psi. Currently the well is injecting only 20 MSCF/D.

The well was originally drilled 104 feet away from Emmons well 117, which was a leaseline water injector up to 1991. The last injection survey was made in May 1990. The log indicated a communication conduit existed to all layers in the San Andres. Well 117was P&A'd with cement plugs above the San Andres reservoir interval, so a communication conduit potentially still exists.

6-28

Well 6-28 was completed with perforations in the B, C, D, E, and F zones in December 1996. The well was acidized at 1440-psi surface pressure, and flowed back to clean up producing water, oil and gas. 77% of the gas was CO_2. A log after injection commenced in February 1997 revealed the well needed a cement squeeze to prevent injectant entering perforations in the A zone. Foamed cement was used to squeeze off all perforations in August 1997 and the E zone reperforated and acidized.

The well did not have a subsequent injection profile.

Well 6-28 was injecting at 600 to 1000 MSCF/D CO2 at injection pressures of 1125 to 1160 psi from June 1997 to Aug 1997, just at the recommended maximum injection pressure of 1150 psi. The well has not injected CO_2 since August 1997.

The well was originally drilled 110 feet away from well 7-07, which was a leaseline water injector up to 1991. The last injection survey was made in May 1985. The log indicated half the injectant entering the lower E zone, with potential communication conduit existing to lower layers in the San Andres. Well 7-07 was P&A'd with cement plugs above the San Andres reservoir interval, so a communication conduit potentially still exists.

The conclusion after working on the three leaseline wells was the foamed cement sealing technique was probably successful in isolating the communication of the San Andres layers.

Where the technique failed was having a method of selective stimulation in the upper layers so that both acid treatments and subsequent CO_2 injection in the upper layers was improved.

ATTACHMENT C: Fractured Reservoir

The Northeastern area of Tract 7, illustrated in FFigure C.1, had some unexpected behaviour since the CO_2 flood started in mid 1996:

1) 7C11H horizontal CO_2 injector appears to have intercepted some form of fracture at the end, or toe, of the well.

2) Unusual CO_2 breakthrough behaviour in wells surrounding the toe of 7C11H CO_2 injector.

3) 6-28 leaseline well appeared to have CO_2 present when it was drilled in late 1997.

4) Interference and Tracer tests inconclusive.

5) Pressure analysis of well 7-10 suggesting proximity to flow barrier.

7C11H Toe

Well 7C11H was drilled and completed open hole in April 1996 in the E zone to a measured depth of 6244'in a northwesterly direction, Figure C.1. Three injection logs have been run since start of injection.

A water injection log, in August 1996 at 500-psi surface pressure, suggested the majority of injectant entering the well between 6025'and 6100'. A CO_2 injection log, in October 1996 at 1196 psi and 3.4 MMSCF/D, suggested a major loss at approximately 6130', Figure C.2. A final water injection log, in October 1997 at 602 psi and 508 -bw/d injection, suggested two major losses from 6100'-6110'and 6150' -6180', Figure C.3. All logs suggested no injectant entering the majority of the wellbore along its 1300'interval. Instead the injectant appeared to be entering the toe of the well somewhere between 6100'and 6180'. A transient fall off test conducted in August 1996 suggested linear flow, interpreted as a fracture in the toe of the well, which tended to confirm the injection logs.

Neutron, resistivity and sonic openhole logs were run in the well prior to injection start up, Figure C.4. The logs suggested the entire E zone had good pay, with porosities between 7 and 14%. The only indication of a fracture is at 6092'where the multi -finger caliper indicated anopening about 1 foot in length.

Prior to injection start up 7C11H was acid washed with coiled tubing. The original procedure recommended surface pressures up to 5000 psi while acidizing the well and during the operation the well was not open to flow. No records of the actual treating pressures have been found so it is difficult to determine if the acid wash caused fracturing at the toe of the well. The end section of 7C11H would have least skin damage and hence more prone to fracturing. Well 6C25H, the other horizontal CO_2 injector, however, had identical drilling and completion practices yet there was no evidence of fracturing in this well caused by acid washing.

The fracture at 7C11H maybe combinations of an original small fracture planes which when acid stimulated at high pressure opened wider. This may explain why the excellent rock in the remainder of 7C11H appears not to be taking any injectant.

It is not clear where the CO_2 entering the toe at 7C11H is disappearing. If it is a fracture system it could be connected to any of the San Andres intervals and the majority of CO_2 may be being wasted. The size of the fracture system is unknown, as is its orientation.

Core data from 7-10 reveals E zone permeability varies between 1 and 10 mD near the toe area of 7C11H. The D zone typically has 0.1 to 1 mD, C zone between 0.8 and 8 mD, B zone 0.1 to 2 mD, A zone 3 to 250 mD. This would suggest the eventual destination for CO_2 would preferentially be the A zone, if the fracture communicates into all layers.

If it is a high permeability streak or small fracture in the E zone it may be injecting in zone, but the areal distribution benefits of the horizontal well are not exploited.

7C11H CO_2 Breakthrough

Wells surrounding the toe of 7C11H are illustrated in Figure C.1. Well 7-10 is physically closest to the toe of 7C11H, followed by 7-01 to the east and 7-02 to the west. Oil, gas, liquid production and gas-oil ratio from 1996 to 1999 are shown in Figures C.5 to C.6. CO_2 injection commenced at 7C11H in August 1996, averaging 2 to 3 MMSCF/D.

Liquid offtake rates at 7-10 and 7-01 were similar throughout 1997, averaging 100 to 200 bf/d. CO_2 breakthrough occurred at 7-10 and 7-01 at similar levels in early 1997, with 7-10 having gas-oil ratios (GOR's) greater than 1 000 SCF/STB, when it was placed on production in January 1997. (Typical GOR during waterflood history is 200 to 400 SCF/STB, Figure C.7). Similarly 7-01 had GORs greater than 1000 SCF/STB starting in January 1997.

Unusually 7-10 has not seen the same CO_2 rate and oil production as 7-01, even though it is physically closer to the toe of 7C11H. Well 7-10 average gas rates are 10 to 30 MSCF/D; at 7-01 rates are 200 to 500 MSCF/D. 7-10 oil rates averaged 5 bo/d in 1997: 7-01 35 bo/d. 2441 MMSCF of CO_2 was injected at 7C11H up to mid 1999, 7-01 produced 252 MMSCF; 7-10 produced 11 MMSCF.

It is therefore apparent the majority of CO_2 is entering the toe of 7C11H and preferentially moving toward 7-01 to the east. Because 7-01 was drilled to the D zone in 1948 and acid treated in open hole, it is unlikely to have much communication to lower layers. Production history, Figure C.8, seems to confirm this with no water breakthrough until 1982, suggesting a uniform sweep of upper San Andres layers, with no lower layer water production evident.

At least some of the CO_2 from 7C11H must therefore be entering the upper layers through the fracture system and processing the CO_2 through the D, E, and F layers toward 7-01.

The fracture at well 7C11H, is believed to have been created by over-injection, during waterflood history. Injection histories for wells surrounding 7C11H are illustrated in Figure C.9 to C.11. There are no injection wells in the immediate vicinity of 7C11H. The closest injection wells are 7

04, 7-07, 8-11, 7-03, 8-18 and 6-28. Only three injection wells 7-04, 7-07 and 8-11 injected for extended periods. Two wells, 7-07 and 8-11, historically injected above fracture pressure. Well 8-11 injected from 1981 to its abandonment in 1991 above 650 psi surface pressure. Well 7-07, a leaseline well, injected from 1979 to it abandonment in 1991 above 650 psi surface pressure. If the fracture is caused by overinjection it was initiated from 7-07 or 8-11.

6-28 First Production

Well 6-28 was drilled in October 1996. The well was completed with perforations in the B, C, D, E, and F zones in December 1996 and acidized at 1440 psi surface pressure. The well flowed back to clean up and produced water, oil and gas on December 20, 1997. 77% of the gas was CO_2. Wells on CO_2 injection by December 1996, Figure C.12, were 7C11H, 2-26, 2-27 and 6C25H, so it is likely the CO_2 was either from 7C11H or 2-26. Well 6-28 was temporarily abandoned on December 30, 1996.

Interference and Tracer Tests

Placed on production test during late January, 6-28 produced 70% CO_2 cut. In order to test communication to 7C11H, a tracer test was attempted between the two wells. On February 25, 1997, a sulphur hexafluoride (SF_6) tracer was injected into 7C11H, with produced gas samples being pulled from 6-28. A small amount of tracer gas was detected at 6-28 within nine hours of injection; however, no additional SF_6 tracer was detected. Although first results seemed to confirm a direct channel from the horizontal injector to 6-28, further investigation of the sampling techniques indicated the sampling might have been tainted, rendering test results inconclusive.

In July 1999 another communication test between 7C11H and 6-28 occurred using a fluorescent dye. Well 6-28 was placed on temporary production from late July 1999 to September 30. Initially the well produced 800 MSCF/d CO_2. After a few days on production 7 bo/d, 41 bw/d and trace CO_2 was produced, suggesting a bank of CO_2 surrounded the well was produced back within two or three days. No more CO_2 was produced at 6-28 during its extended test.

Well 7C11H was converted from CO_2 to water injection on July 28, 1999, injecting at 550 to 600 psi and 990 to 1200 bw/d. On August 6, 1999 a batch of fluorescent dye was injected along with the water. Sampling was quite frequent at 6-28 during the first few hours after the dye was added, but no dye was detected either initially or throughout the remainder of the extended test.

When 7C11H was converted back to CO_2 injection on August 20, 6-28 still had no signs of CO_2, again suggesting no direct communication path through a fracture system was evident in 1999.

Sampling also occurred twice a day in 8 wells (6-28, 7-08, 7-15, 7-02, 7-05, 7-10, 7-01 and 7-13) surrounding 7C11H's toe area. No dye detection was evident in any of these wells from July through September.

Unusually, however, a "random" sample taken from 7-12 in early September did indicate dye presence. 7-12 is due south of 7C11H toe, and injectant would have to pass by 7-05 before getting to 7-12. 7-05 is believed to have good integrity in the upper San Andres (drilled to the base of E zone in 1948, was not nitro shot, and production history suggests no lower layer

communication). 7-12 is a modern well, drilled in 1995, perforated in the E and F zones and acid stimulated 3 times ranging from 2768 psi in 1995 to 1338 psi in July 1997. The bottom perforation in the E zone at 4733'is only 22'above the original oil -water contact in the D zone. Some of the production may therefore be coming from below the E zone. A conformance log would be recommended to determine the source of production. The acid stimulation in July 1997, may well have tapped into lower layers as offtake prior to stimulation was 10 bf/d and water cuts reached almost 100%.

Another interference test was initiated in June 1998. This time to test communication between 2-26 and 6-28, as preferential fracture direction is believed to be east-west from mini frac testing of 6-21 and 6-23, Figure C.13. Gauges were placed in 6-28 on June 12, and replaced by a second set of gauges on the June 22, and subsequently pulled on the July 2. Through this period CO_2 rates and injection pressures were monitored in all surrounding injection wells, Figure C.14 and C.15.

At approximately 280 hours gauges were installed in 6-28. At 300 hours well 2-26 was shut in, with no apparent change in pressure decline at 6-28. 2 -26 was injecting at 350 hours, at higher rates and pressures, but again there was no response from 6-28. 2-26 was shut in just under 400 hours with no response at 6-28. If a fluid filled infinitely conducting fracture exists between the two wells there should be fairly rapid pressure response, but none was evident.

The most noticeable change in pressure is at 420 hours. This could be related to increased injection rate at 6C25H or 7C11H, Figure C.16. It is difficult to relate later rate changes to responses at 6-28.

Overall no definite fracture communication can be seen between 6-28 and another well with this interference test.

7-10 Build Up Analysis

During February 1993 a downhole gauge was installed at 7-10 for a 72 hour pressure build up to determine E zone permeability and skin after an acid stimulation the previous month. The diagnostic plot, Figure C.17, reveals a definite radial flow section followed by a change in derivative behaviour characteristic of a boundary effect. Using the values of permeability and skin determined from radial flow a reasonable match of the derivative is achieved by assuming a no flow boundary 50' from 7 -10, Figure C.18. The duration of build up was not long enough to determine whether the boundary is sealing or partially sealing, but it indicates communication across the boundary would be impaired (test was performed prior to drilling of 7C11H).

Based on this information and the lack of CO_2 production seen at 7-10 it could mean CO_2 being injected at 7C11H will have difficulty supporting wells on the other side of the boundary, to the North.

Conclusion

It is difficult to conclude the fracture system encountered at 7C11H toe is still connected to either 6-28 or 2-26, as results from recent interference and dye tests conflict with the original assumptions of fracture systems in this area. It could be concluded, due to lowering of injection

pressures, that sealing up of induced fractures may have occurred since the start of CO_2 injection in mid 1996.

ATTACHMENT D : Simulation Model

The simulation model was originally built in the mid 1990s to help justify the CO_2 flood at South Cowden and Emmons Units. It is the only tool that can attempt to quantify the incline in oil production expected from the CO_2 flood. There are, however, several issues with the model that should be understood before using any of its predictions as an accurate determination of flood performance.

There are seven layers, which model only the upper layers of the San Andres (layers C through F). The E zone is split into 4 layers to improve modelling of heterogeneity and fluid segregation effects. There is no modelling of layers A, B or any Grayburg layers.

There is therefore no modelling of out of zone injection during waterflood history or during CO_2 prediction. This can be seen in some of the original history matching output where injection volumes exceed simulation history match volumes. Out of zone injection is currently modelled by assuming an "in zone" fraction for each injection well.

In parts of South Cowden Tract 2 or Emmons where layers A or B are above oil-water contact and are perforated, no prediction of performance is available for lower layers from the simulation model. Any comparison of simulation production rates with actual is therefore impossible without knowledge of zonal allocation in this area.

Some of the outer tracts at South Cowden are not modelled, such as Tract 3 where prod uction came from the uppermost layers in the San Andres and Grayburg.

In some areas of South Cowden and Emmons the model does not match individual well behaviour within acceptable error. Areas such as 7-10 proved too difficult to history match on a well basis, so the well was taken out. Matches from the wells grouped together surrounding 7-10 to produce grouped production history, and compared to simulation history, proved more successful for matching purposes.

The model does not include descriptions of faulting or fracturing, caused by historical overinjection. Therefore only areas of no fracturing may have reasonable forecasts.

The model does not allow for communication through old plug and abandoned wells where communication may be an issue. These communication effects are therefore difficult to quantify.

The current simulation model may give acceptable prediction for the field as a whole, but on an individual well basis is poor. It should only be used for justifying field scale changes to operating strategy.

Rather than re-building the entire model, it would be recommend to concentrate modelling efforts using sector modelling to try and understand influence of old wells and how communication to lower zones effects performance. Does this explain CO_2 breakthrough? What would expected production profile be if CO_2 were processing a water wet lower zone? How

does heterogeneity in E zone effect production rate, can this explain any early breakthrough? What are the optimum locations for any lateral wells?

If improvements in the CO_2 flood are being observed, it would be recommended to rebuild the full field model, incorporate lower layers to model out of zone injection in the southern/eastern part of the field, properly model areas such as Tract 2 above oil water contact, and incorporate finer layer scale, if deemed necessary, to model heterogeneity. Improve history match of CO_2 performance and processes seen to date (discussed in Attachment E). The rebuilt model should be capable of being used for the 20-25 year life of field and give realistic forecasts for reserves and budgeting purposes.

ATTACHMENT E: CO_2 Process North of 6C25H

The area to the north of horizontal CO_2 injector 6C25H is believed to have the best in zone injection at South Cowden. This area was picked to study whether the CO_2 processes are effective and if the simulation model is forecasting correctly.

There are 7 wells (7-13, 6-20, 6-23, 5-07, 6-29, 6-19 and 6-02) north of 6C25H, Figure E.1. The majority of CO_2 response at these wells is believed to have sourced from 6C25H, as very little of the CO_2 is injected in zone at the leaseline wells further north.

Figure E.2 illustrates how oil and gas (CO_2) rates have changed since start of CO_2 injection at 6C25H in mid 1996. Response from CO_2 can be seen starting mid 1997 in wells 6-19, 6-02, 6-23 and 6-20. Other wells 6-29, 7-13 and 5-07 have had little or no response to date.

Comparison of simulation prediction against actual oil recovery as a function of CO_2 injected at 6C25H is illustrated in Figure E.3. As can be seen there is a good agreement of simulation predicted recovery north of 6C25H where CO_2 is entering in zone in the upper layers of the San Andres.

Figure E.4 illustrates oil, water and gas (CO_2) rates as a function of CO_2 injected at 6C25H. Simulation oil rates appear to be slightly under-predicting the actual rates seen in the field. Simulation water rates appear to be over-predicting actual field rates. Both simulation oil and water rates appear therefore to be conservative predictions. Gas (CO_2) rates, however, appear to be under-predicting the level of CO_2 production actually seen in the field. This can also be seen in predictions of GOR against CO_2 injected at 6C25H, Figure E.5. The simulation will therefore require adjustments to improve predictions of the three phases. In the interim the simulation predictions, for areas where the CO_2 is in zone, provides conservative oil recovery estimates but with an under-prediction of gas production will influence CO_2 recycle expenses.

ATTACHMENT F: Early CO_2 Breakthrough

Well 6-22 was initially perforated and acidized in the E zone in December 1995 and immediately a bridge plug set above the E zone (refer to Figure A.4). The San Andres F and G zones were perforated and acidized and the well placed on production with the bridge plug in place above the E zone. The bridge plug was pulled and all perforations acidized in August 1997. Offtake rates measured during late 1997 were 250 to 270 bf/d, which then dropped to under 50 bf/d in

early 1998. A plug was re-set above the E interval in April 1998 because of safety concerns of high CO_2 rates in late 1997.

The CO_2 early breakthrough in 6-22 appears to have originated from below the F zone because the highest CO_2 rates measured occurred when the bridge plug was pulled in August 1997. The CO_2 rates did drop in early 1998 prior to resetting the bridge plug above the E zone but this was probably due to the reduction in productivity observed from January to April 1998, due to asphaltine or scale build up in the upper San Andres.

As to why the CO_2 broke through at 6-22 and not in 6-21 remains a concern. A similar breakthrough can be seen in 6-17, Figure F.1 to the northeast of 6-21, so one explanation could be the presence of high porosity/permeability intervals within the E zone, which are evident on both 6-17 and 6-22 logs.

The actual full field simulation model has the E zone broken down into three layers to account for heterogeneity effects. The model prediction, as a function of cumulative CO_2 gas injected at 6C25H is shown in Figures F.2, F.3 and F.4. Breakthrough of CO_2 was not anticipated until 2000 to 4000 MMSCF injection at 6C25H. Breakthrough actually occurred between 1000 and 2000 MMSCF. Similarly, breakthrough at 6-17 occurred slightly earlier than anticipated, and the CO_2 rate appears to be considerably higher than predicted. This tends to indicate premature breakthrough at 6-22 and 6-17 could be related to more heterogeneous intervals than modelled currently.

An alternative explanation for premature breakthrough is related to the degree of communication between San Andres intervals in old P&A'd wells such as 6-13, Figure F.5. Well 6-13 was P&A'd in 1995 with a plug above the Grayburg perforations, which allows communication between all open perforations. The well is therefore capable of acting as a conduit for E zone CO_2 injection at 6C25H to either Grayburg or the lower San Andres intervals.

Note: Both 6-03 and 6-07 are close to 6C25H horizontal injector. They were nitro-glycerine shot in the late 1940s and left with open hole completions, they were both temporarily abandoned in 1997 with cement plugs injected into the open hole section. This should prevent communication between layers in the San Andres.

A third explanation of early breakthrough is the CO_2 has originated from out of zone injection at the toe of the 7C11H horizontal CO_2 injection well. Core data from the nearby 7-10 well suggest the lower layers of the San Andres have high permeability streaks compared to the upper layers. This is correlation repeated in any well that has core data down to the lower San Andres interval such as the 8-19 well.

The toe injection at 7C11H could therefore be entering the lower San Andres and communicating to wells such as 6-22 in the southern part of the lease through the high permeability layers in the lower San Andres.

Further sector simulation modelling using finer scale layering or alterations to the current full field model would be recommended to improve understanding of why CO_2 has premature breakthrough in these wells.

Appendix G

ATTACHMENT G: Redevelopment Options

Well-By-Well Review

120 South Cowden and leaseline wells were reviewed to determine whether operational work would be recommended to improve the CO_2 flood performance. The operational work could be broken down into the following categories for each well:

Correctly abandon a well
Abandon a currently temporarily abandoned well
Run a conformance log
Polymer treatment to seal up reservoir in near well area
Downhole pressure test
Convert to injection
Stimperf and heated acid treatment
Cement squeeze, stimperf and heated acid treatment
Cement, drill 1 short radius lateral
Cement, drill 2 short radius lateral
Cement, drill 3 short radius lateral
Section casing, cement, drill 1 short radius lateral
Section casing, cement, drill 2 short radius lateral
Section casing, cement, drill 3 short radius lateral

Costs and timing for each operation were estimated to provide a total cost required for each well, Figures G.1A and G.1B. Note that all costs are preliminary in this figure.

A total South Cowden redevelopment, using the well-by-well costs described above, was broken down into phases, Figure G.2. Phase I being the highest priority (improving offtake in the main CO_2 area), Phase VI being least priority.

A preliminary rig schedule for this activity, assuming three rigs, is shown in Figures G.3A and G.3B. Rig 1 concentrating on short radius laterals, rig 2 working on conformance issues, and rig 3 working on other work such as logging/stimulations/upgrading disposal well.

A summary of timing and cost for each phase is illustrated in Figure G.4.

Using the redevelopment phases, simulation model cases were built to predict the changes in oil forecasts and CO_2 purchasing and re-cycling requirements. These were generated for each phase on the assumption each phase would follow on from previous phase if it proved to be successful.

For example, Phase II (improving in zone injectivity/productivity and disposal capability) would occur if short radius lateral technology proved to be successful during Phase I. In this way the redevelopment expansion could be assessed for further improvements in different areas, each requiring extra increments of capital during year 2000.

During early stages of simulation modelling it became apparent Phases 3 and above dramatically increased the amount of CO_2 production, as a result of extra productivity from several lateral wells. The current facilities, however, can only re-cycle a maximum of 8.6 MMSCF/D CO_2.

Therefore all subsequent cases were re-built with this surface constraint. Previous modelling had not required this constraint as CO_2 production was predicted to be less than 8.6 MMSCF/D.

Economic cases were then built for each phase, using the simulation model predictions for CO_2 purchase, re-cycle volumes, oil volumes and capital requirements from Figure G.4.

The economic cases are summarized in Figure G.5. The original incremental recovery for the project predicted 12.34 MMSTB. This is the incremental recovery above continued waterflooding of the lease. The current "as-is" CO_2 flood (if the lease is left to continue with current level of CO_2 purchase, no change to out of zone injection and only upgrading the CO_2 compressor in year 2000) would be expected to recover only 3.06 MMSTB.

As can be seen the optimum redevelopment appears to be option 2, which is the combination of Phases I and II. The higher options have greater levels of operating expense related to CO_2 re-cycling, bringingthe abandonment year forward in time and recovering fewer reserves.

A summary of the recommended Phases I and II work is shown in Figures G.6 and G.7. Maps showing the location of laterals, plug and abandon recommendations and stimulation candidates are shown in Figures G.8 and G.9.

Option 2 does not recover the expected 1995 AFE forecasts. It does however improve the flood from its current level of performance. With a successful redevelopment using the lateral and conformance techniques outlined in Phase I and II, further expansion of the CO_2 flood to areas not considered economically floodable may increase recovery further. Areas such as Tract 2 and the eastern margin of the lease, which were not originally considered for CO_2 flooding, may prove to be economically viable through use of short radius laterals which increase CO_2 processing and throughput in poorer quality rock.

Option 2 does appear to be the most economically viable of the options to consider. It is, however, using techniques not proven to Phillips in West Texas both from a cost and production stand point. It is therefore recommended to take a cautious approach to the South Cowden redevelopment by closely monitoring the performance of the Phase I laterals prior to investing larger capital sums for the Phase II work.

The technical challenges are summarized in Figure G.10. The most difficult of these challenges is thought not to be the actual lateral drilling itself but the preparation of the well prior to lateral drilling. Most wells at South Cowden suffer from poor communication behind pipe, which allows lower and upper layers to backflow. This is of most concern at vertical CO_2 injection wells where injectant is entering perforations in the upper San Andres but communicating to higher permeability lower layers.

It is also an issue for current producers that are lateral candidates. Any communication through the incorrectly abandoned vertical well section will allow backflow from lower layers to the lateral section in the upper layers. This may produce unwanted lower layers in preference to the required upper layers.

Several cementing techniques were tried in during 1995-1997 to seal up behind pipe communication at leaseline wells 6-26, 62-7 and 6-28. The most successful used foamed

cements and it is likely similar preparation techniques will be required. Multi-rate injectivity tests and conformance logs will be run in each well to determine if conformance activities are required on each well.

ATTACHMENT H : LESSONS LEARNED FROM IMPLEMENTING CO_2 FLOOD AT SCU

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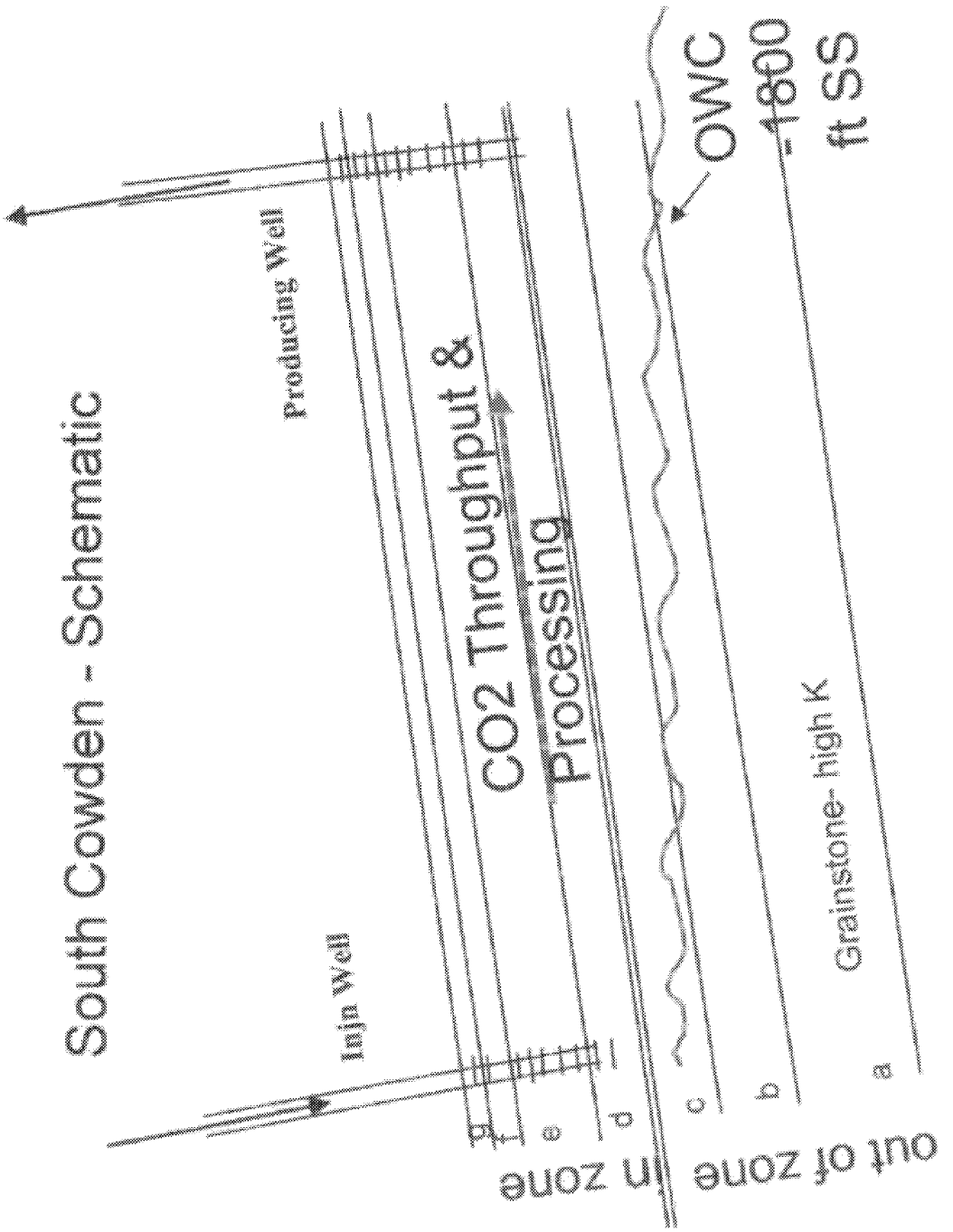

South Cowden - Schematic
Producing Well
Inja Well
CO2 Throughput & Processing
OWC
-1800 ft SS
Grainstone- high K
a
b
c
out of zone
in zone

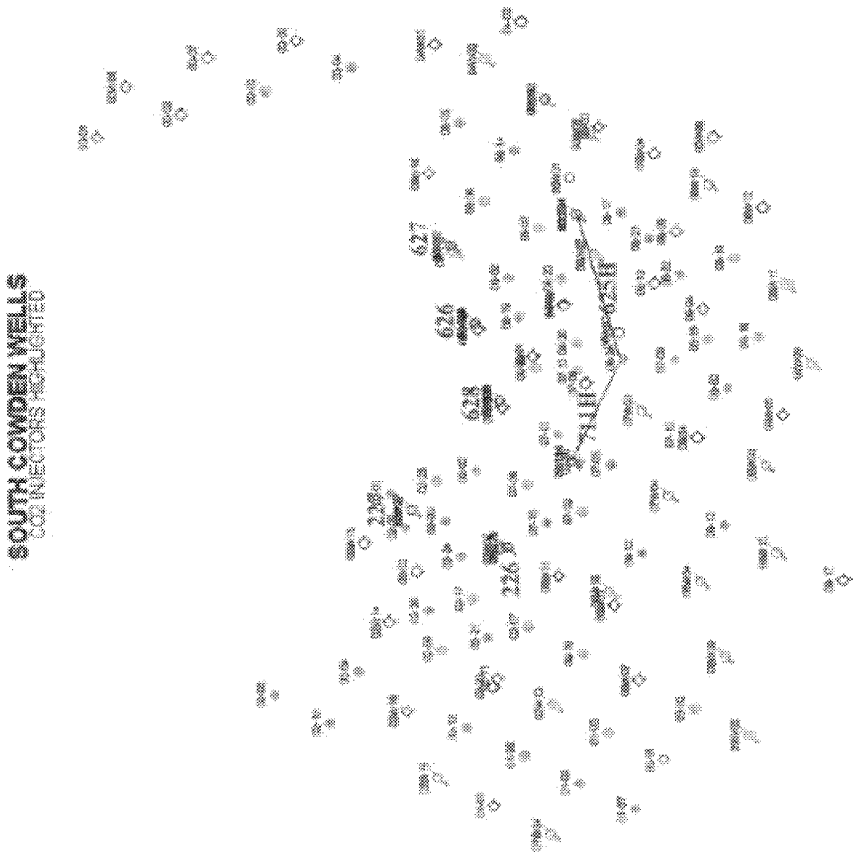
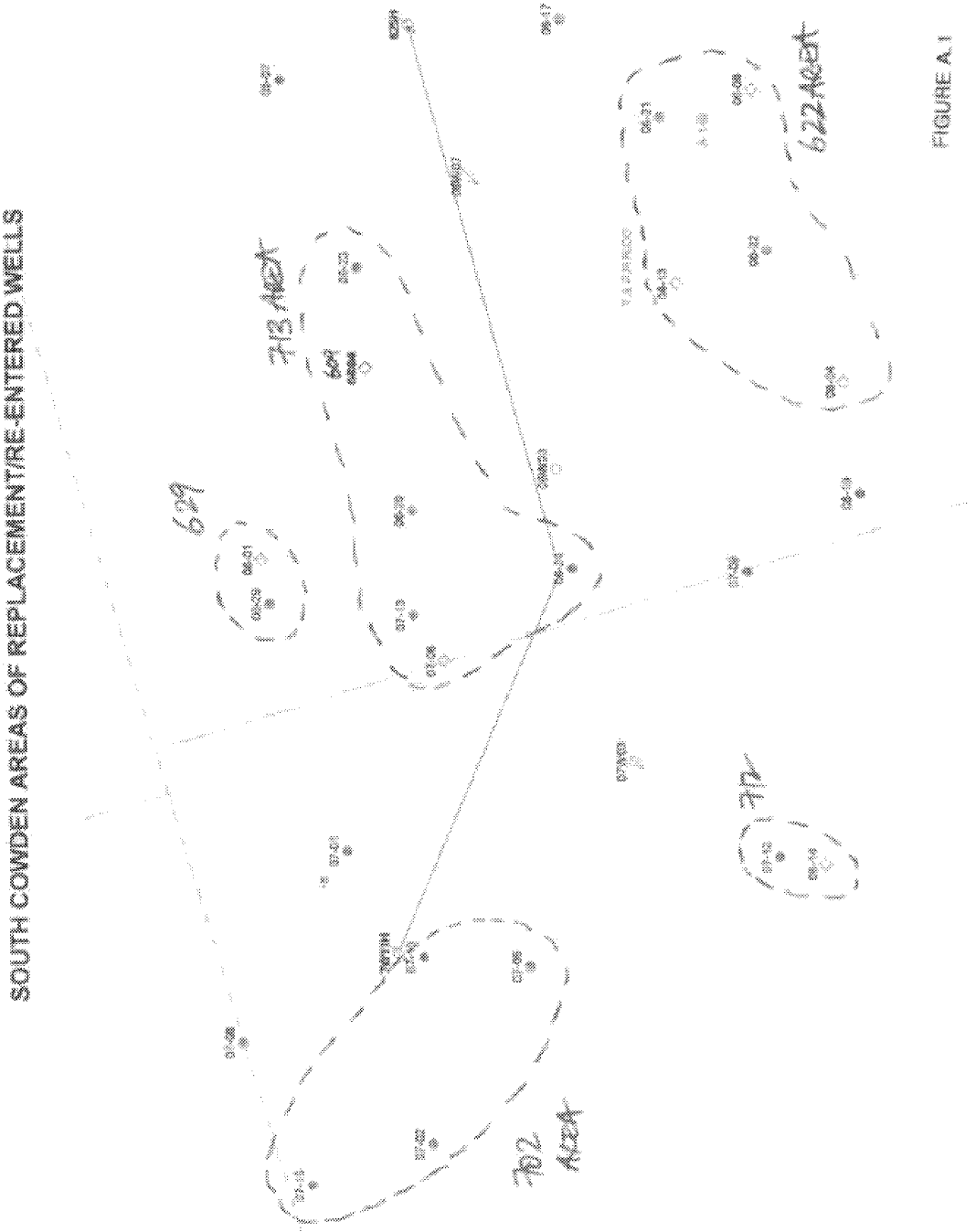


FIGURE 2


SOUTH COWDEN AREAS OF REPLACEMENT/RE-ENTERED WELLS
FIGURE A.1

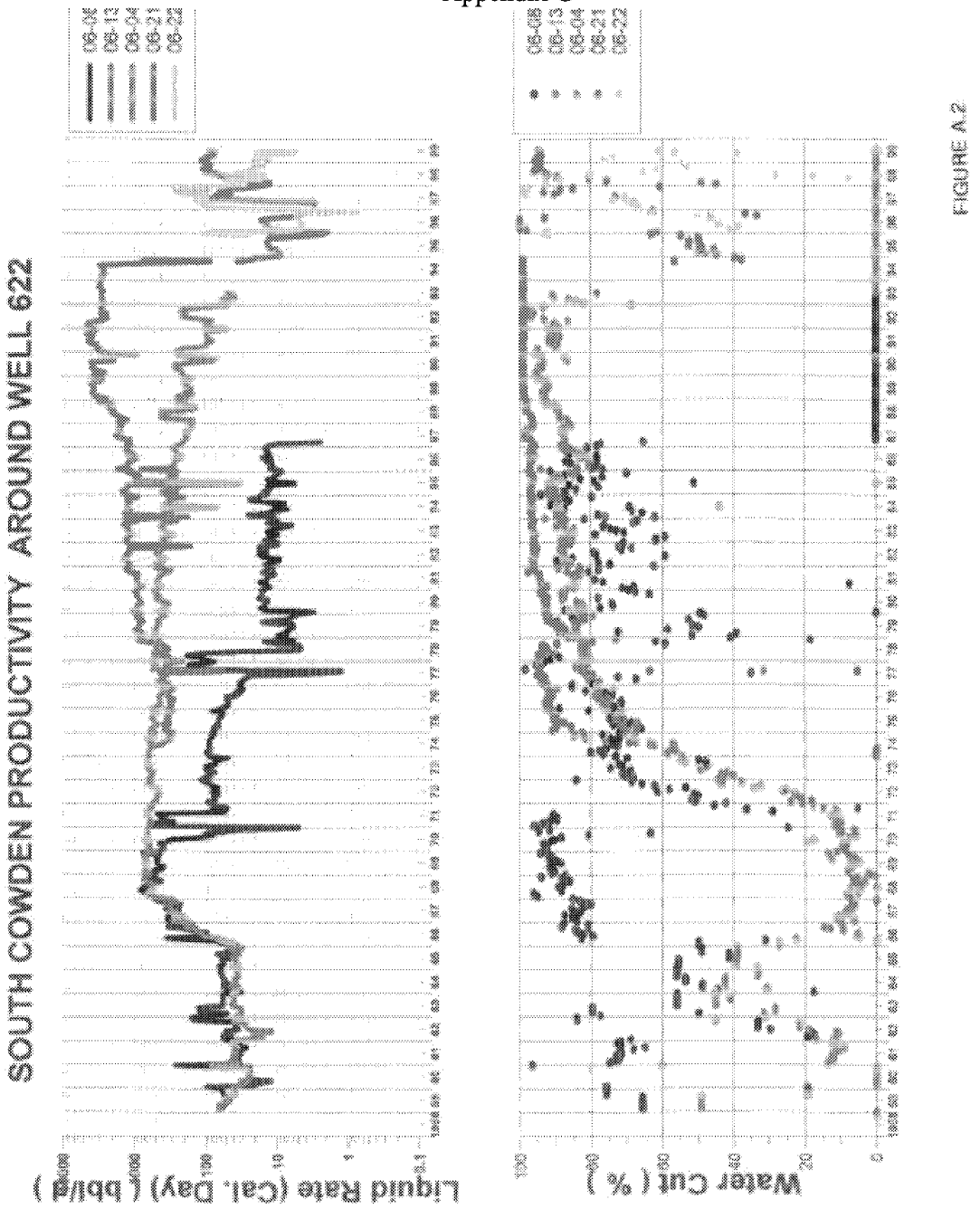
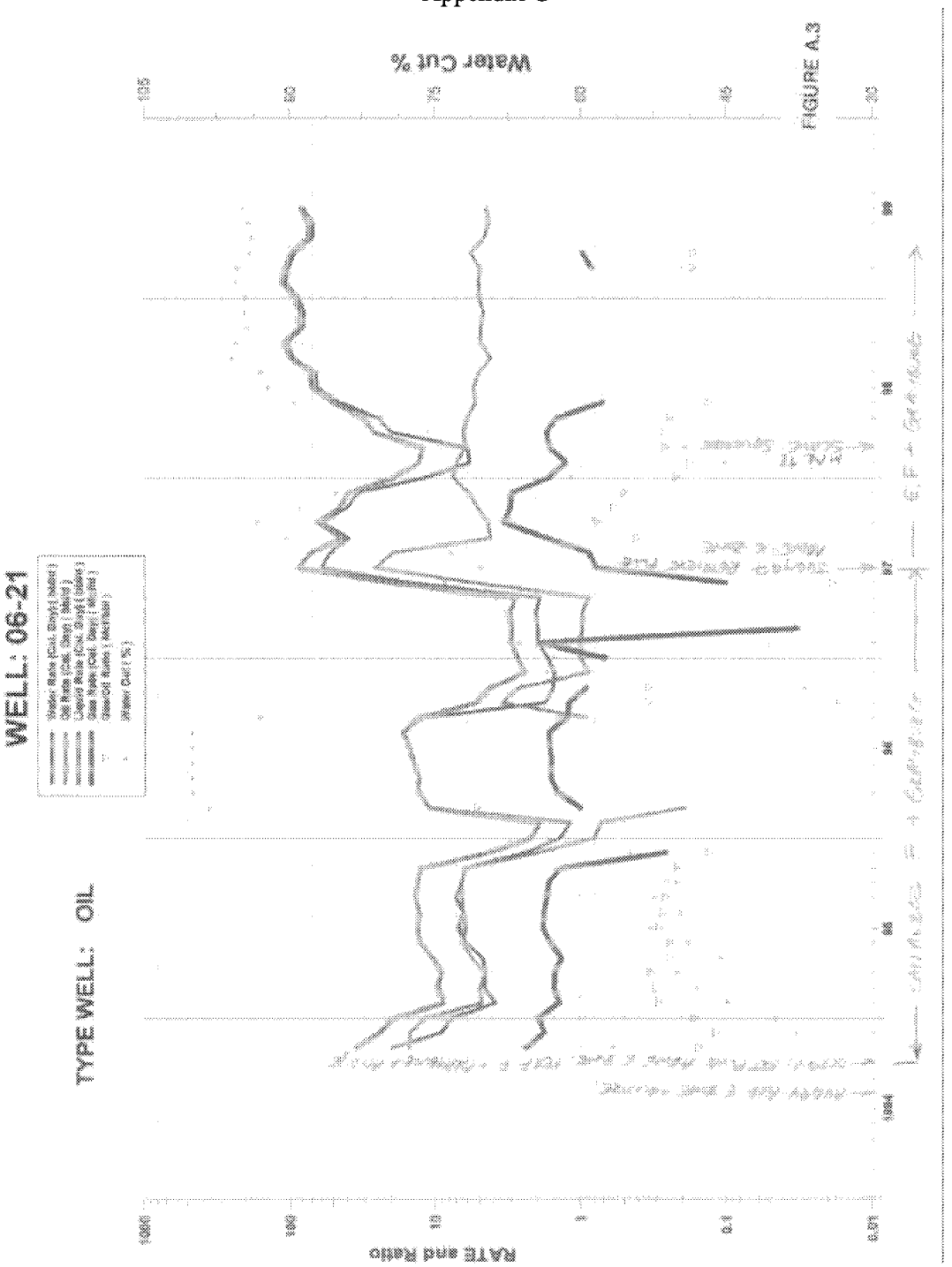

SOUTH COWDEN PRODUCTIVITY AROUND WELL 622
08-05
08-13
08-04
08-21
08-22
Liquid Rate (Cal. Day) (bbl/d)
Water Cut (%)

FIGURE A-2


WELL: 06-21
TYPE WELL: OIL
RATE and Ratio
Water Cut %
FIGURE A.3

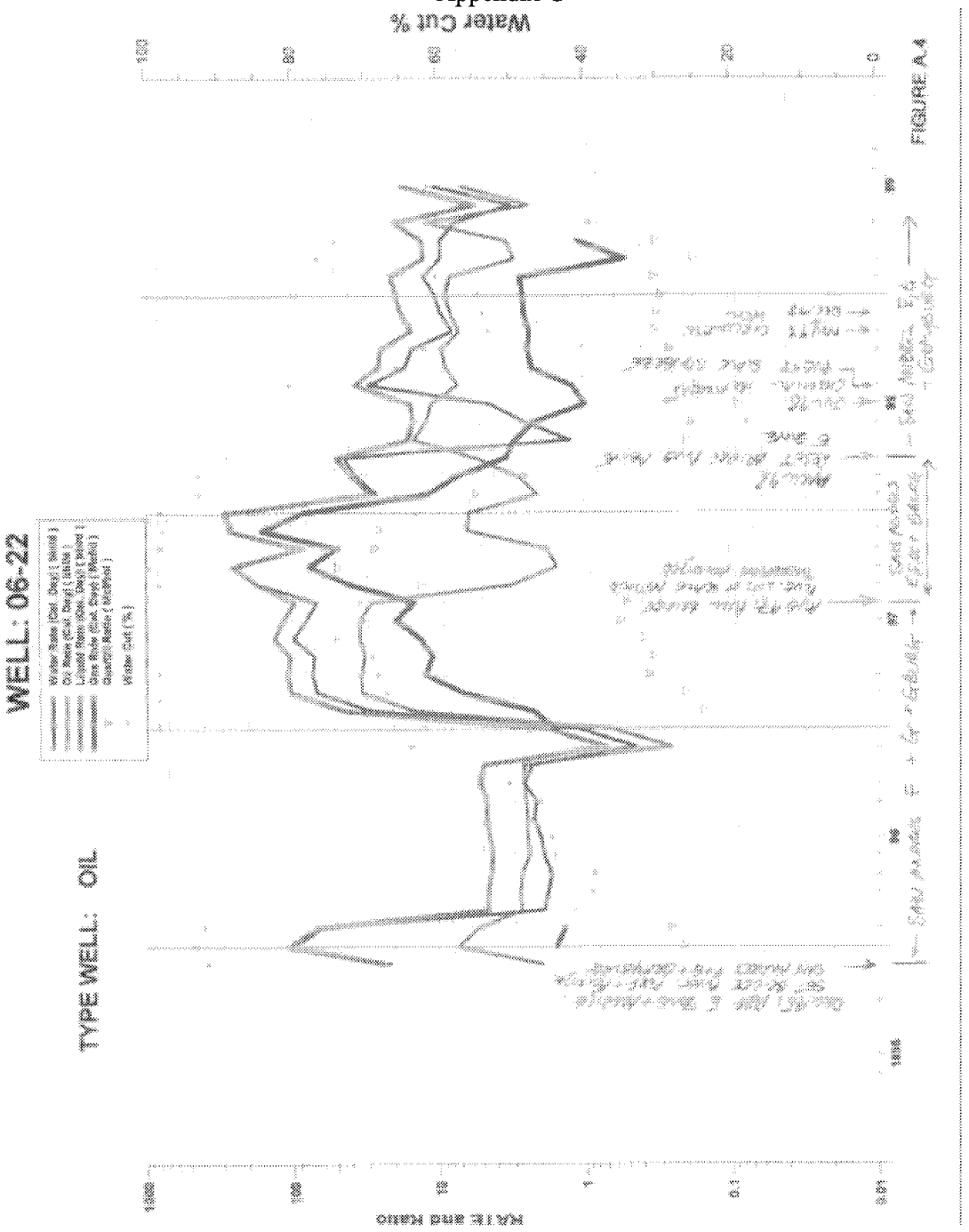


FIGURE A.4

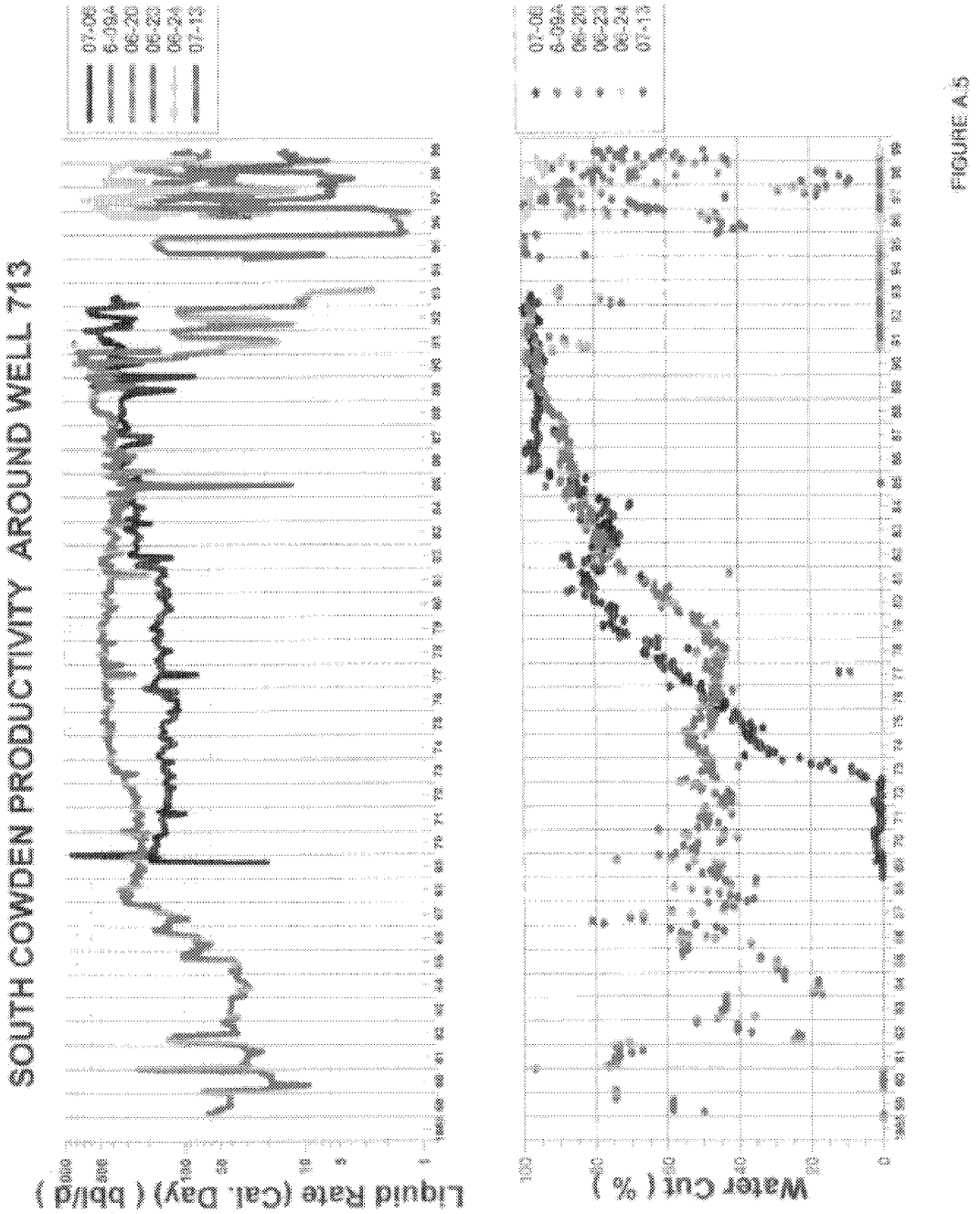
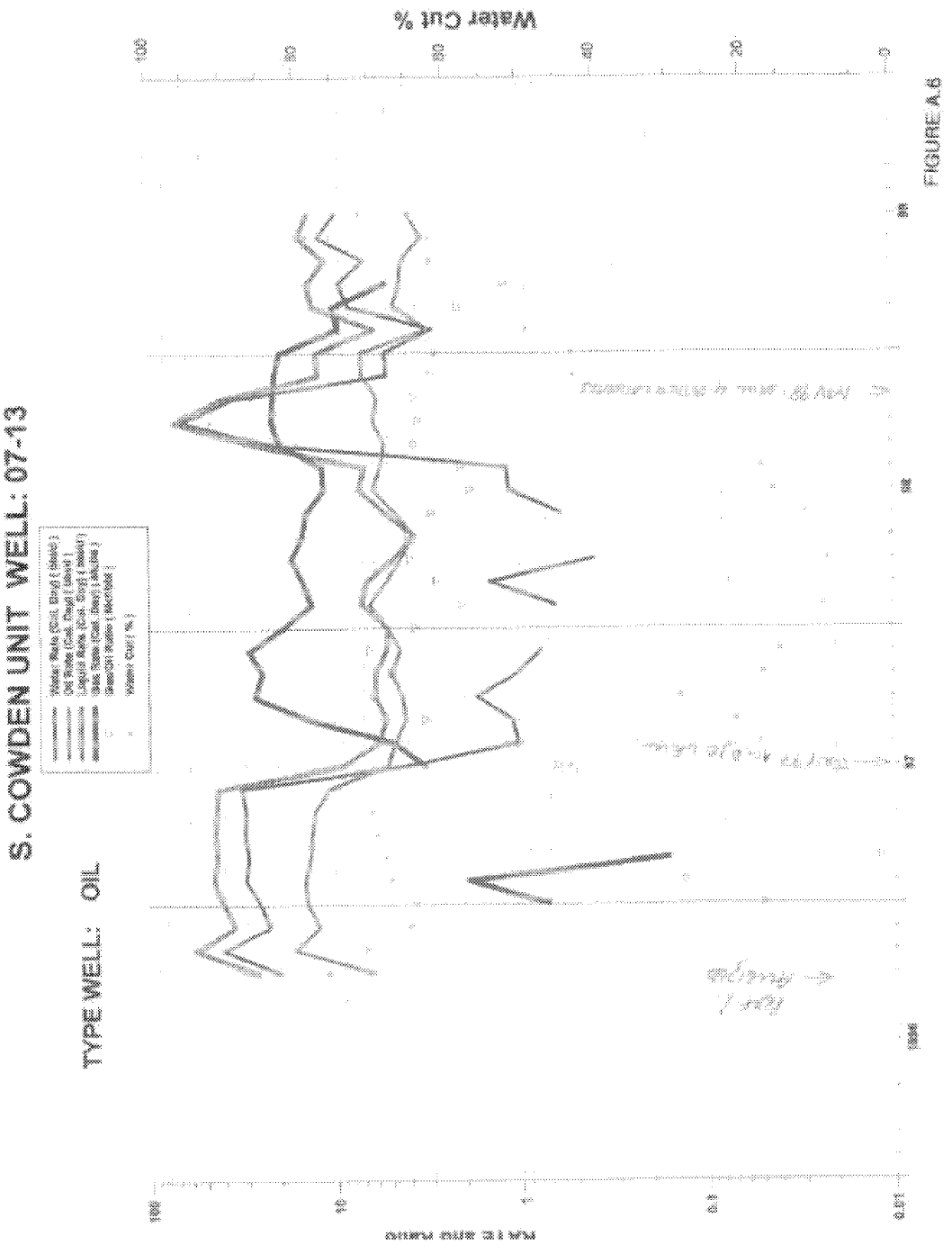

SOUTH COWDEN PRODUCTIVITY AROUND WELL 713
07-06
A-08A
08-20
08-23
08-24
07-13
Liquid Rate (Cal. Day) (bbl/d)
Water Cut (%)

FIGURE A.5


S. COWDEN UNIT WELL: 07-13
TYPE WELL: OIL
Water Cut %
FIGURE A.6

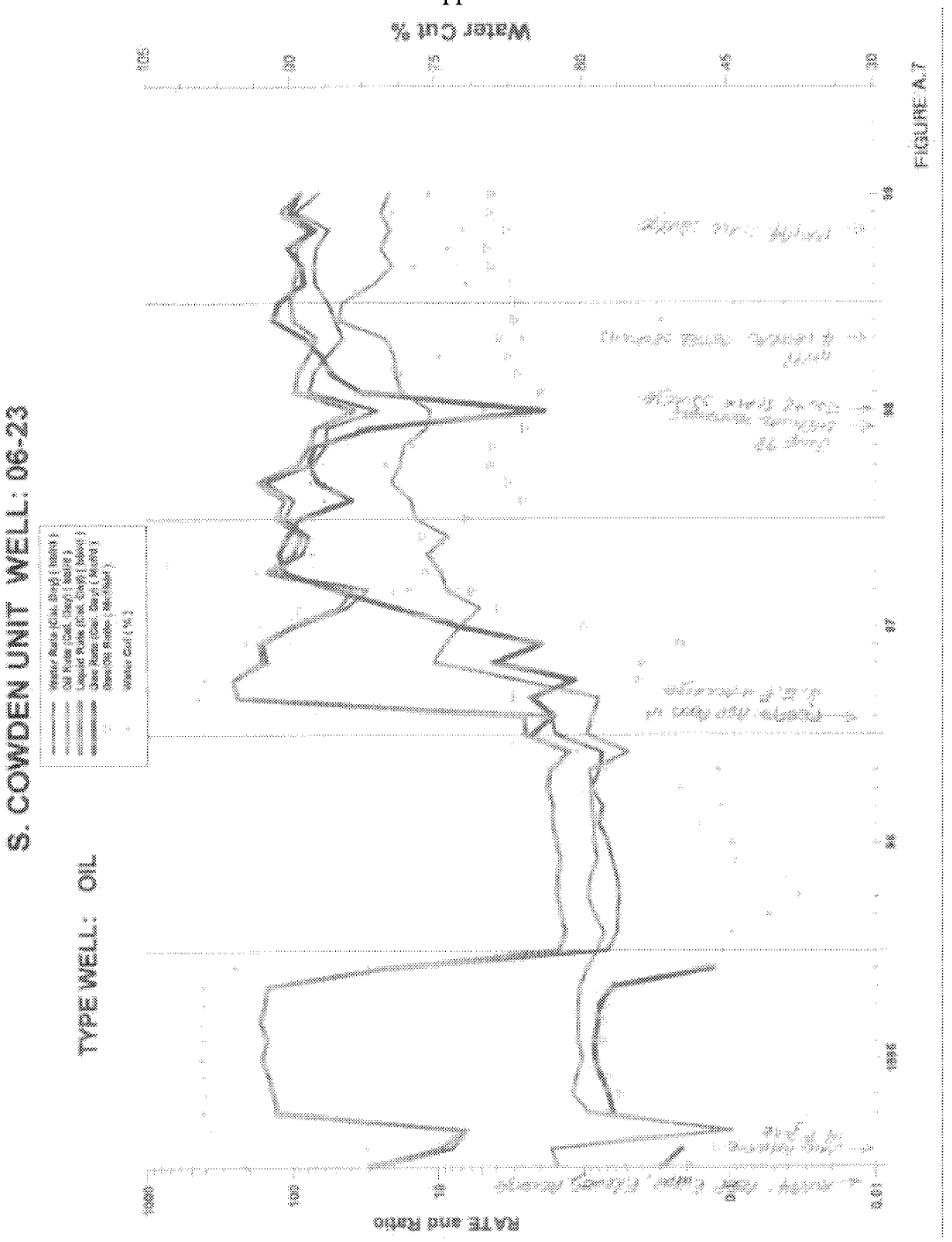

S. COWDEN UNIT WELL: 06-23
TYPE WELL: OIL
Water Cut %
RATE and Ratio

FIGURE A.7

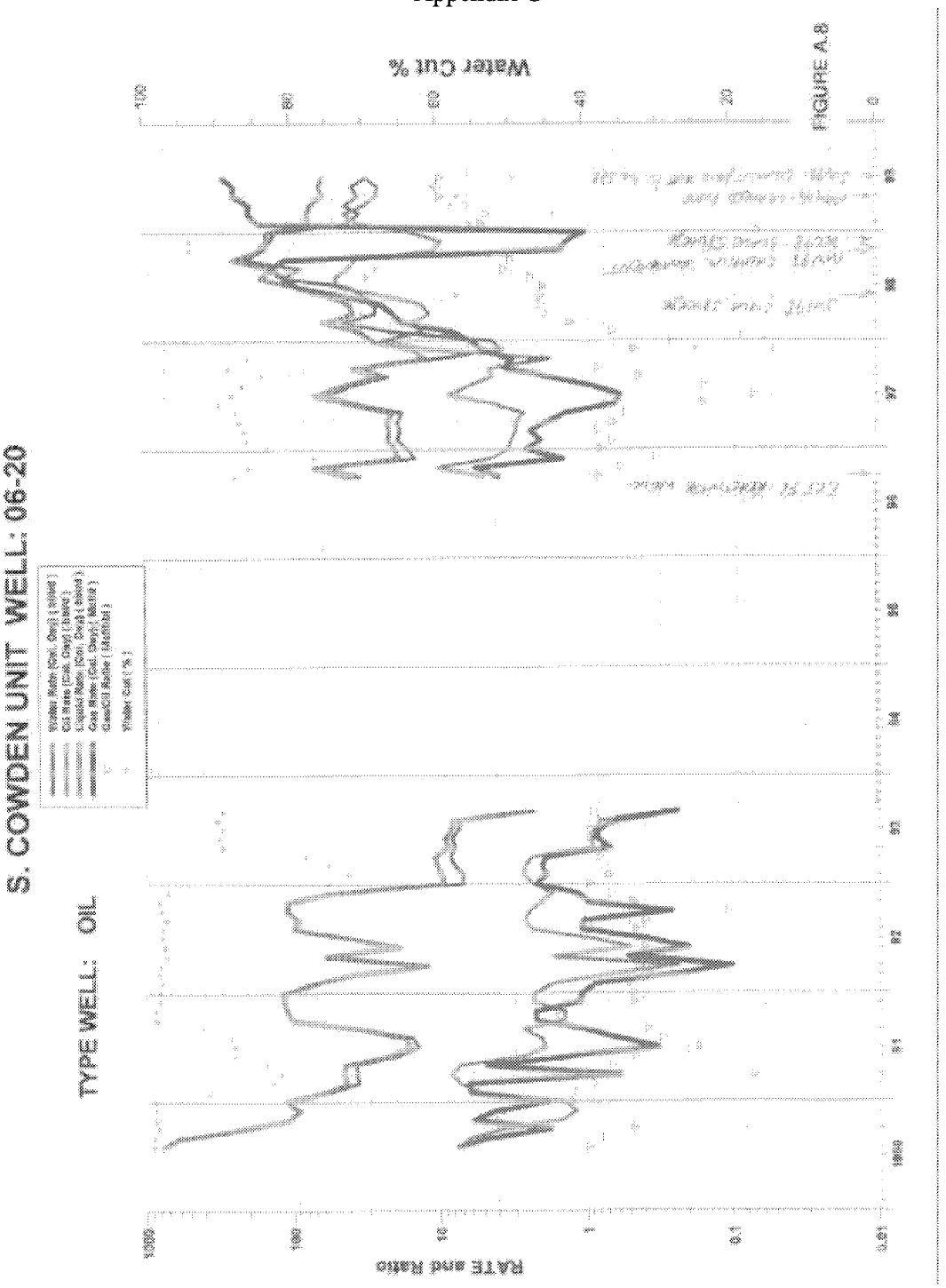

S. COWDEN UNIT WELL: 06-20
TYPE WELL: OIL
RATE and Ratio
Water Cut %

FIGURE A.8

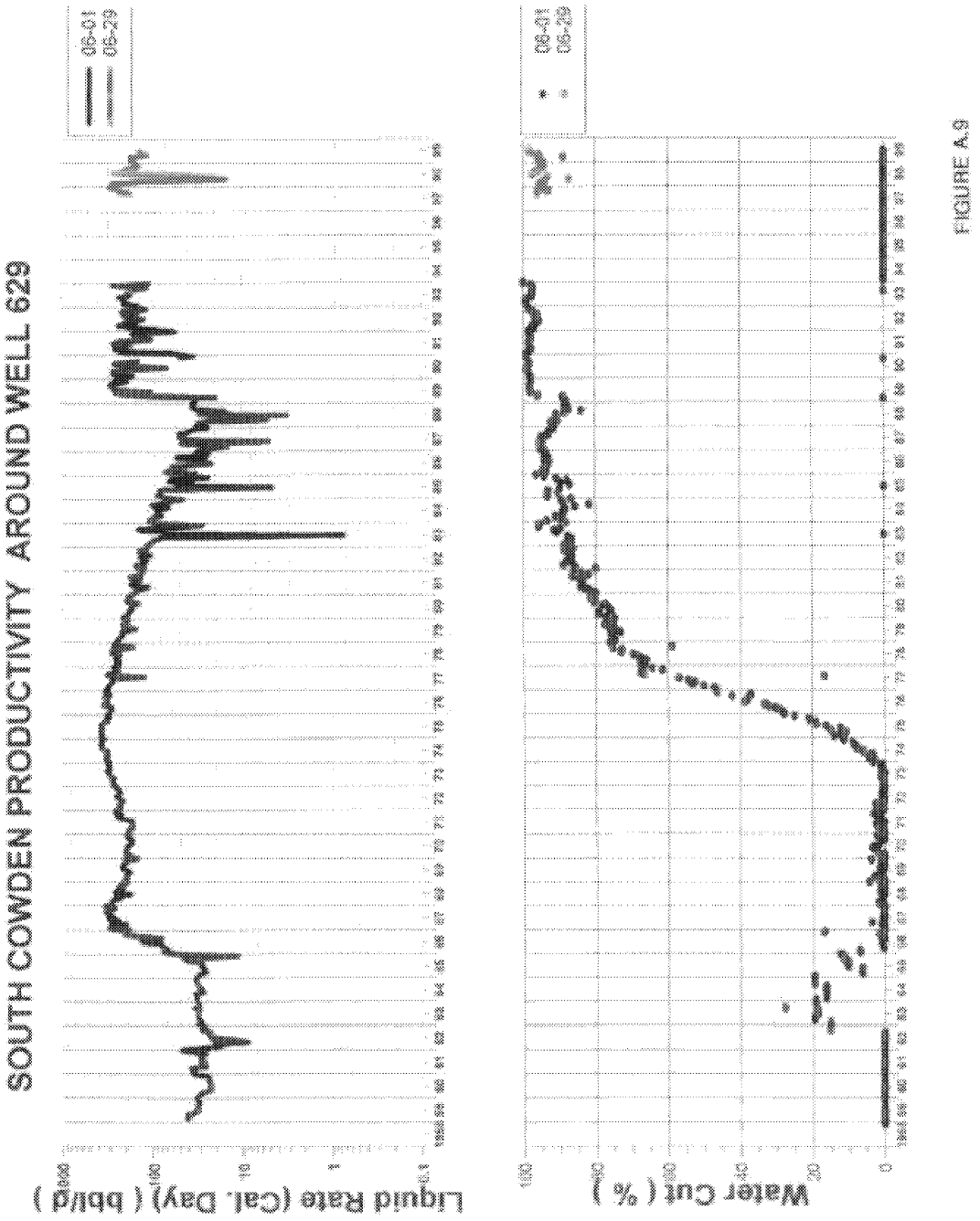
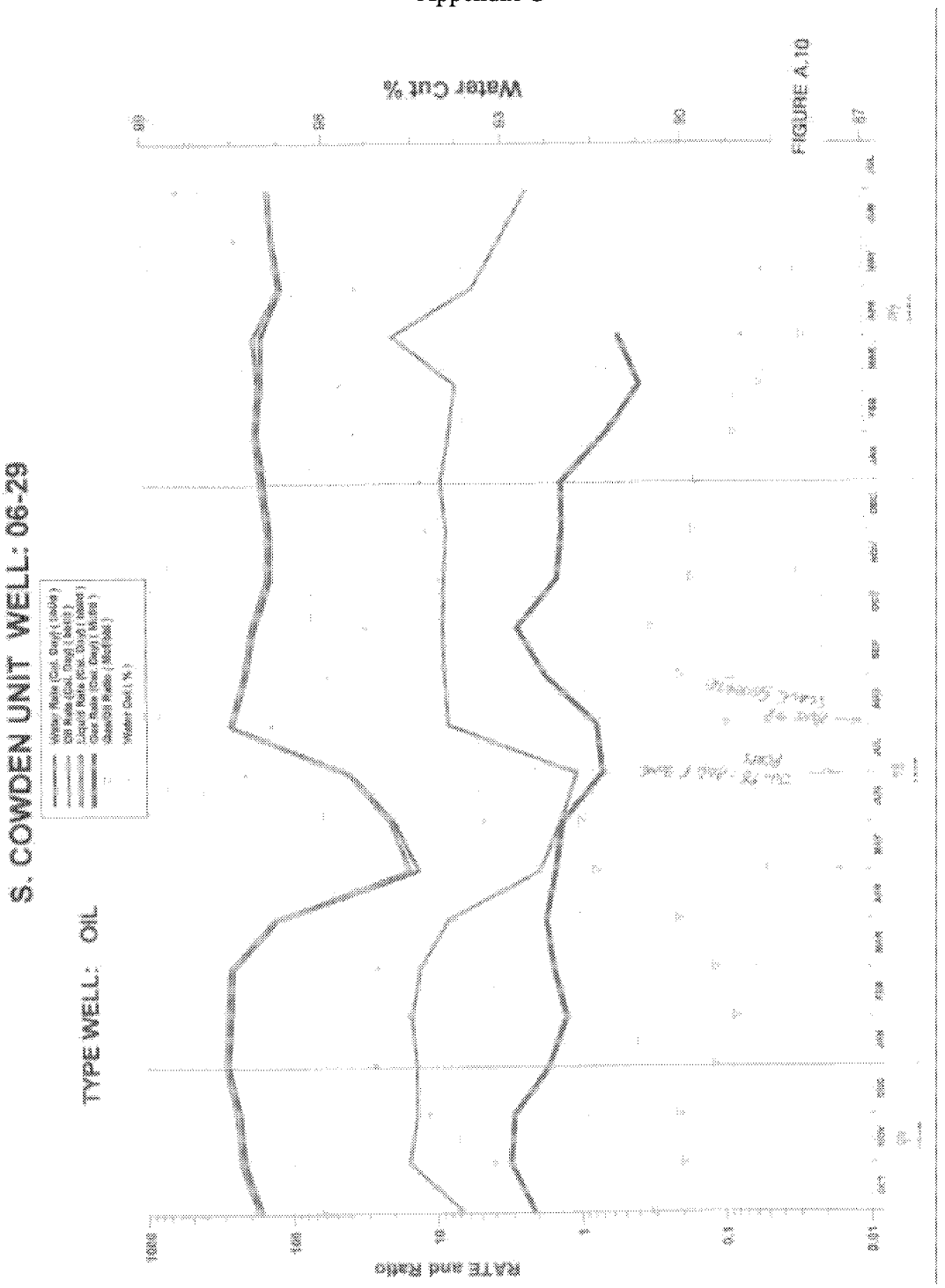

SOUTH COWDEN PRODUCTIVITY AROUND WELL 629
06-01
06-29
Liquid Rate (Cal. Day) (bbl/d)
Water Cut (%)

FIGURE A.9


S. COWDEN UNIT WELL: 06-29
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A.10

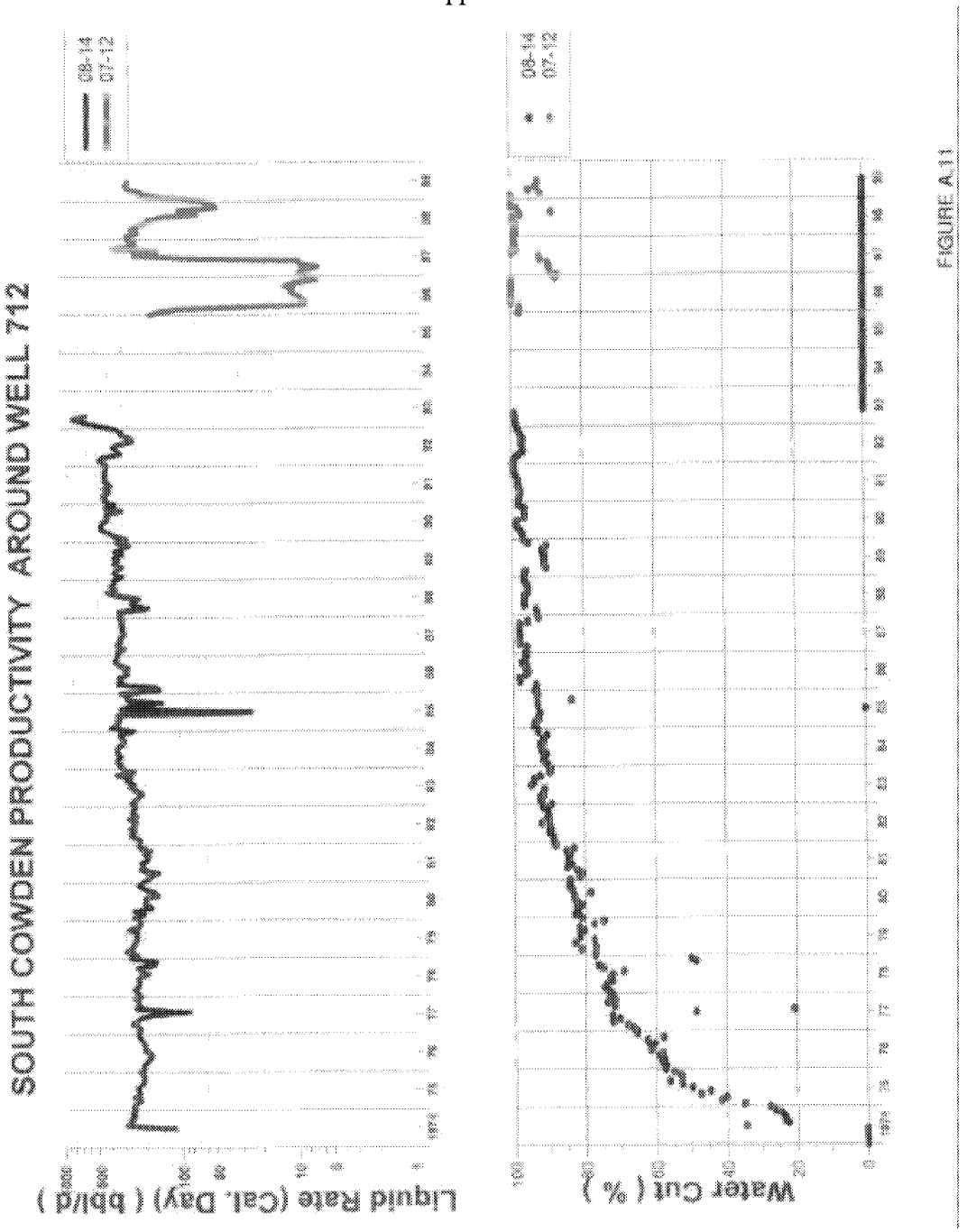

SOUTH COWDEN PRODUCTIVITY AROUND WELL 712
08-14
07-12
Liquid Rate (Cal. Day) (bbl/d)
Water Cut (%)

FIGURE A.11

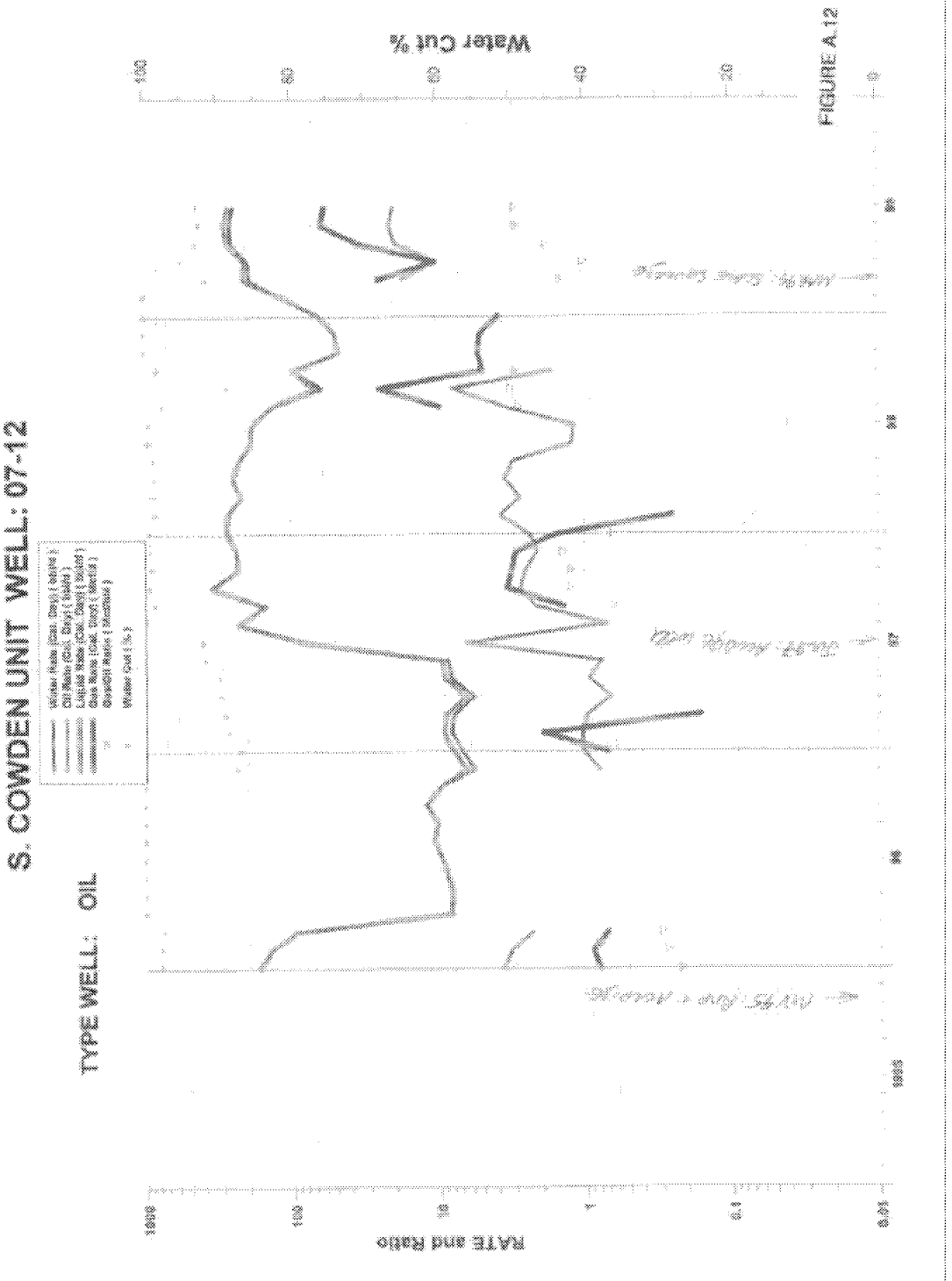

S. COWDEN UNIT WELL: 07-12
TYPE WELL: OIL
RATE and Ratio
Water Cut %

FIGURE A.12

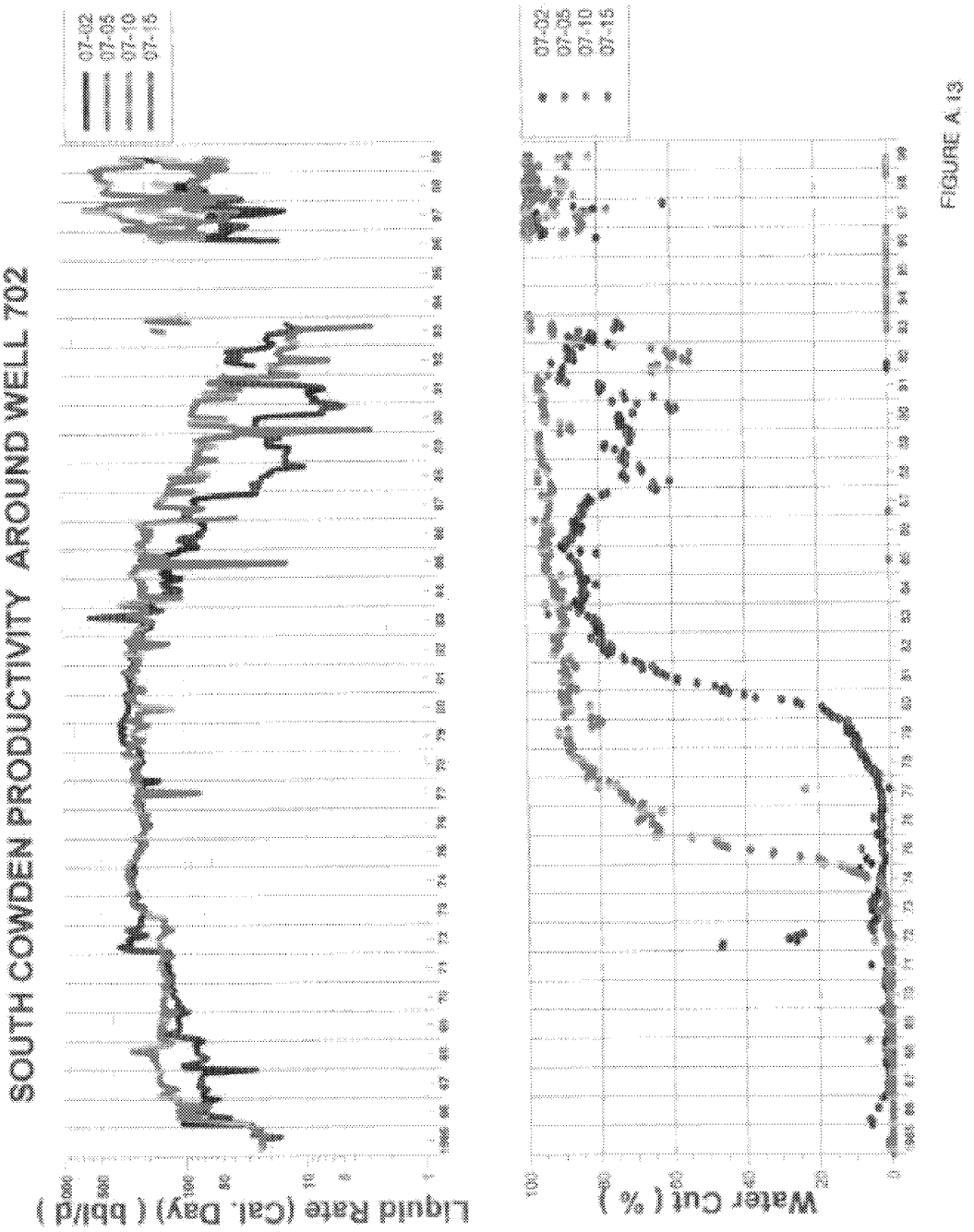
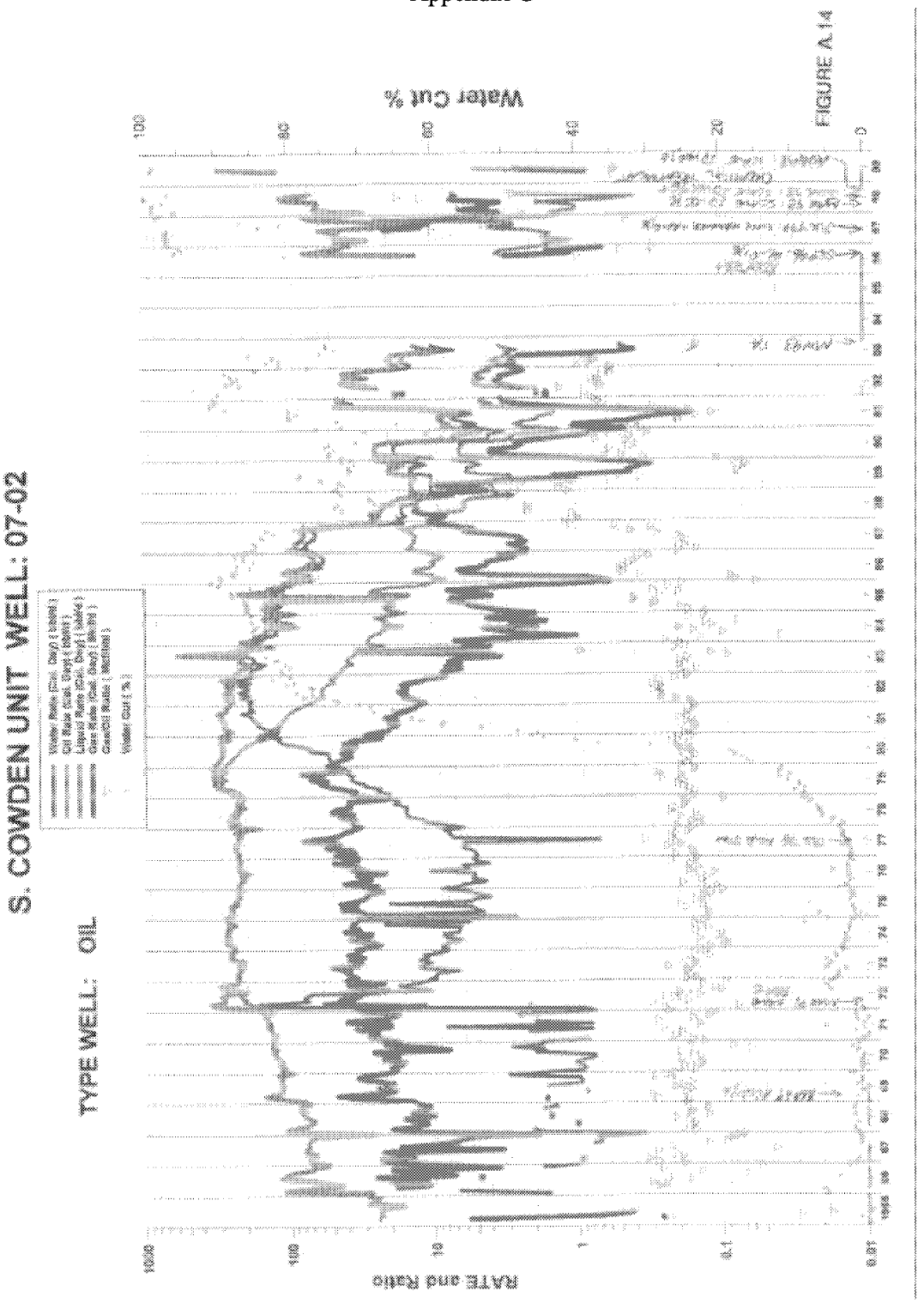
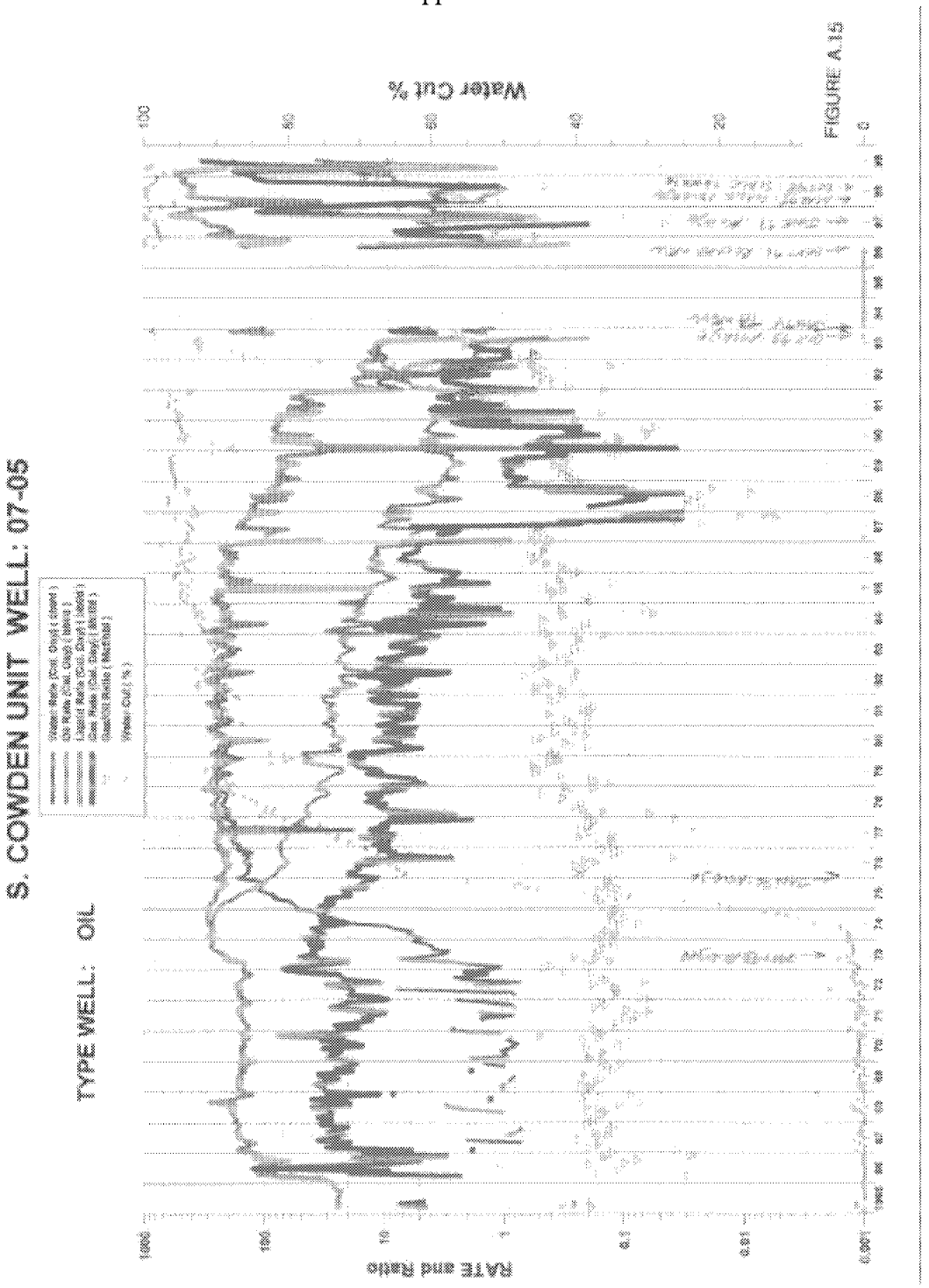
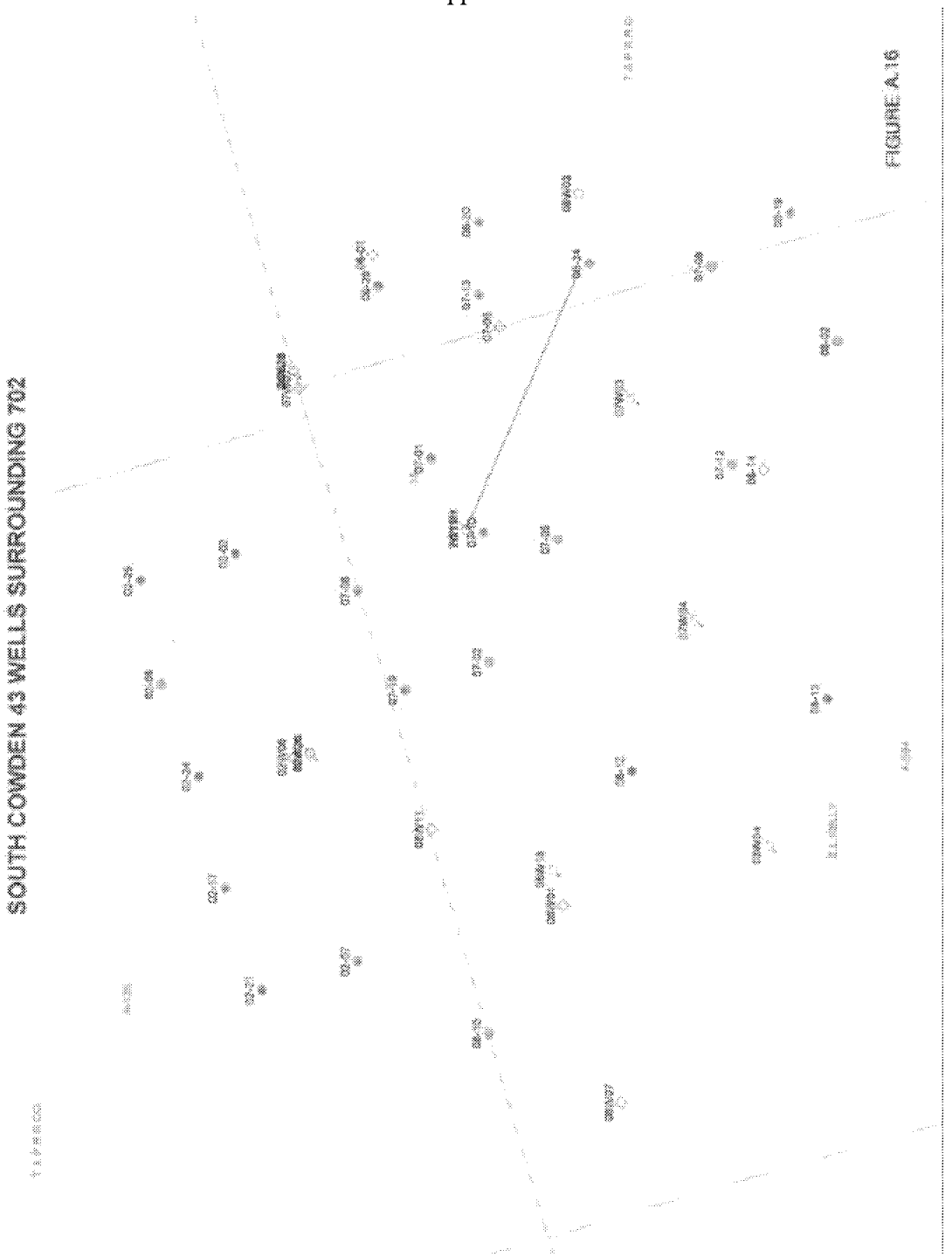

SOUTH COWDEN PRODUCTIVITY AROUND WELL 702
07-02
07-05
07-10
07-15
Liquid Rate (Cal. Day) (bbl/d)
Water Cut (%)

FIGURE A.13


S. COWDEN UNIT WELL: 07-02
TYPE WELL: OIL
RATE and Ratio
Water Cut %
FIGURE A.14


S. COWDEN UNIT WELL: 07-05
TYPE WELL: OIL
RATE and Ratio
Water Cut %
FIGURE A.15


SOUTH COWDEN 43 WELLS SURROUNDING 702
FIGURE A.16

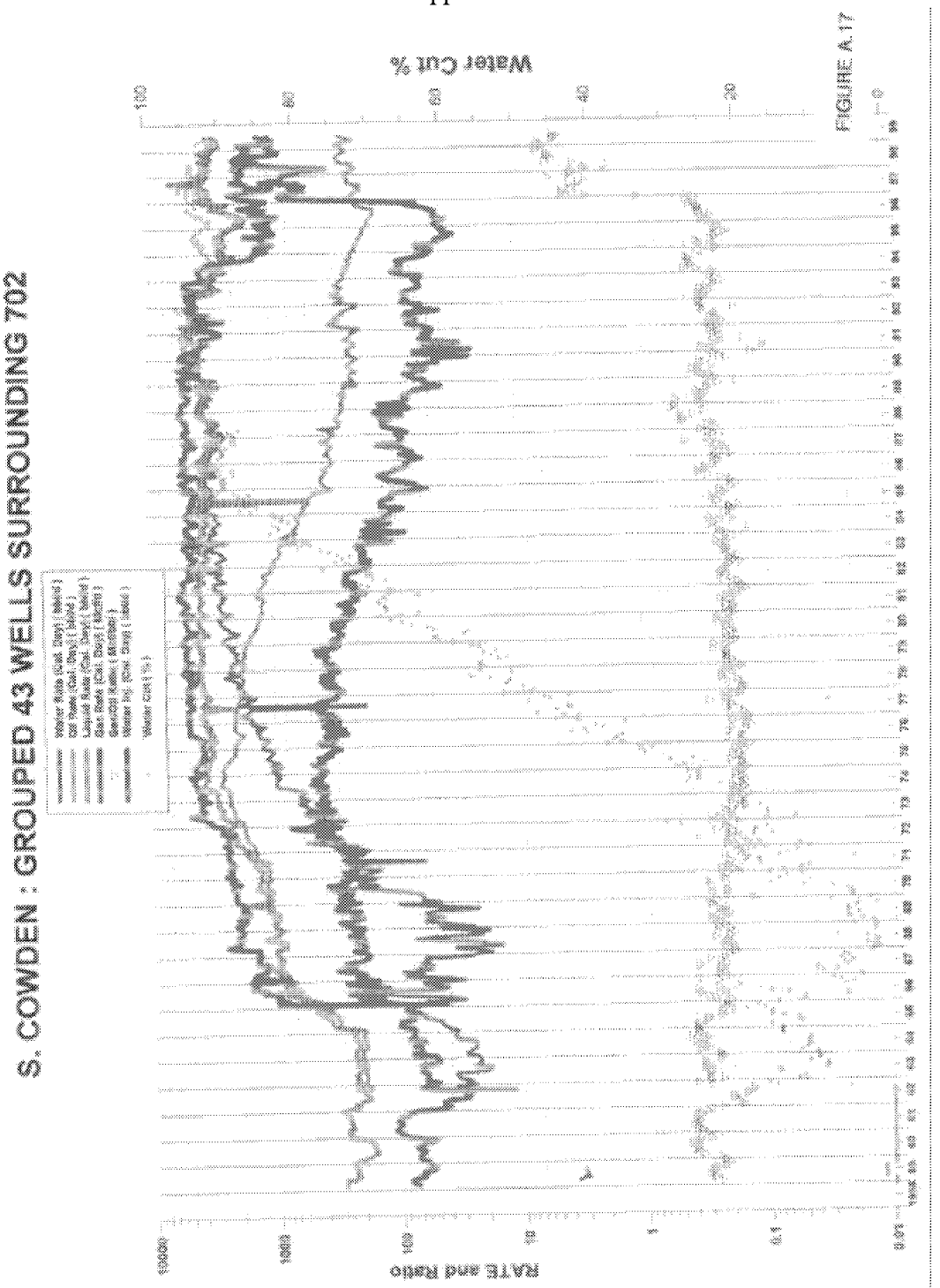

S. COWDEN : GROUPED 43 WELLS SURROUNDING 702
Water Cut %
RATE and Ratio
100
80
60
40
20
0
1000
100
10
1
0.1
0.01

FIGURE A.17

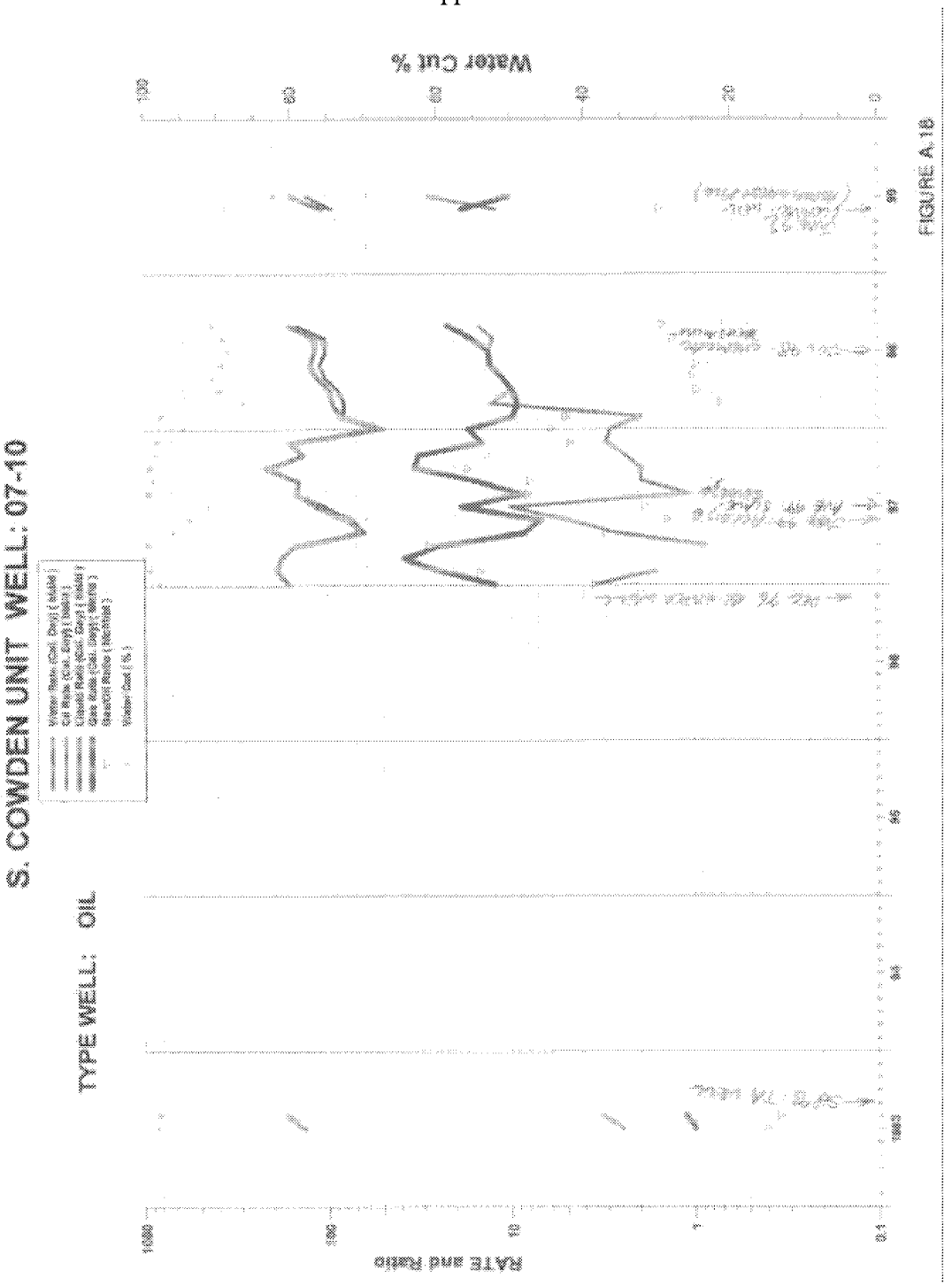

S. COWDEN UNIT WELL: 07-10
TYPE WELL: OIL
RATE and Ratio
Water Cut %

FIGURE A.16

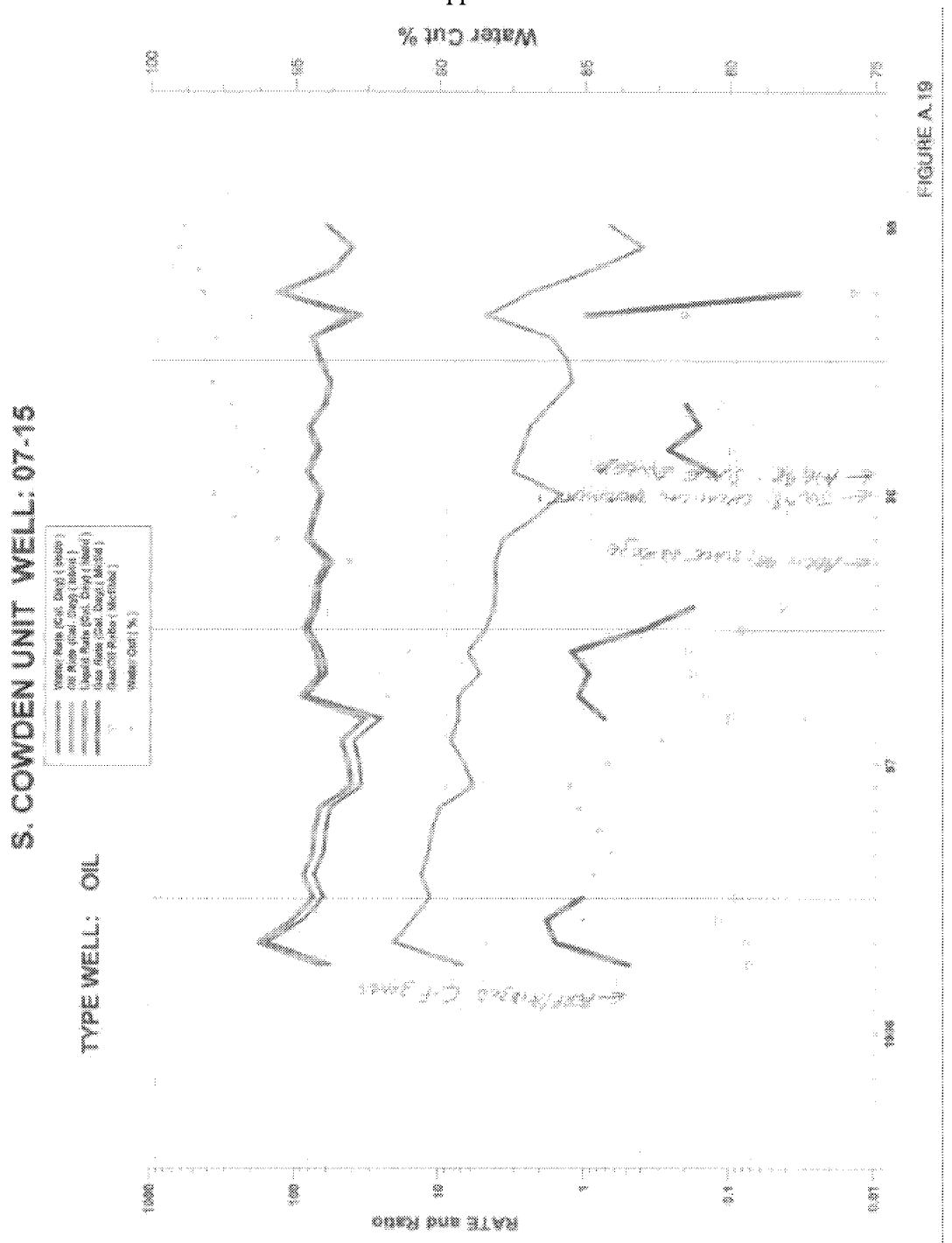

S. COWDEN UNIT WELL: 07-15
TYPE WELL: OIL
RATE and Ratio
Water Cut %

FIGURE A.19

SUMMARY SOUTH COWDEN UPPER SAN ANDRES PRODUCTIVITY

REPLACEMENT OR RE-ENTERED WELLS

WELL	AREA	ACTUAL		EXPECTED	DIFF	Percent		EXPECTED	DIFF	Percent		Diff	Percent
				based on	Actual v			based on	Actual v			Exp Sim v	
				history	Exp			AFE sim model	Exp			Exp hist	
		BFPD		BFPD	BFPD	Diff %		BFPD	BFPD	Diff %		BFPD	Diff %
621	622	108		600	-500	-83		150	-50	-33		-450	-300
622	622	258		600	-350	-58		150	108	67		-450	-300
713	713	18		150	-135	-90		290	-275	-95		140	48
623	713	100		150	-50	-33		250	-150	-60		100	40
620	713	80		150	-70	-47		150	-70	-47		0	0
629	629	150		300	-150	-50		240	-90	-38		-60	-25
712	712	250		250	0	0		150	100	67		-100	-67
702	702	50		150	-100	-67		150	-100	-67		0	0
709	702	300		150	150	100		250	50	20		100	40
710	702	100		150	-50	-33		n/a					
716	702	75		150	-75	-50		250	-175	-70		100	40
TOTAL		1470		2800	-1330	-48		2030	-560	-33		-420	-31
*- actual productivity during periods when all upper San Andres zones were open.													

11/03/1999 NEW_REENTERED_AFE_VS_ACTUAL

FIGURE A.20

SOUTH COWDEN PRODUCTIVITY IMPROVEMENT POTENTIAL

WELL	CURRENT		POTENTIAL	DIFFERENCE	POTENTIAL*		WELL	CURRENT		POTENTIAL	IFFERENCE	POTENTIAL*
	FLUID RATE	OIL CUT	FLUID RATE	POTENTIAL -	INCREMENTAL			FLUID RATE	OIL CUT	FLUID RATE	POTENTIAL -	INCREMENTAL
	Jun-99	Jun-99	SIMULATION	CURRENT	OIL RATE			Jun-99	Jun-99	W/FLOOD	CURRENT	OIL RATE
	BF/D	%	BF/D	BF/D	BO/D			BF/D	%	BF/D	BF/D	BO/D
621	74	5.8	150	76	4.4		621	74	5.8	600	526	30.5
622	5	43.21	150	145	62.7		622	5	43.21	660	589	257.1
713	15	21.68	290	275	59.6		713	15	21.68	150	135	29.3
623	114	20.53	250	136	27.9		623	114	20.53	150	36	7.4
620	62	39.59	150	88	34.8		620	62	39.59	150	88	34.8
629	127	2.64	240	113	2.9		629	127	2.64	300	173	4.4
712	278	7.55	150	-128			712	278	7.55	250	-28	
702	115	1.33	150	35	0.6		702	115	1.33	150	35	0.6
705	197	9.69	250	53	5.1		705	197	9.69	150	-47	
710	106	11.19	n/a				710	106	11.19	150	44	4.9
715	41	0.99	250	209	2.1		715	41	0.99	150	109	1.1
TOTAL					200.0		TOTAL					370.0

** - Increase expected if well offtake rates improved to the originally anticipated rates.*

NB: 622 not currently producing from E zone.

11/08/1999

NEW_REENTERED_AFE_VS_ACTUAL

FIGURE A.21

SOUTH COWDEN SUMMARY OFFTAKE RATES FOR DIFFERENT COMPLETIONS

ORIGINAL WELL	DRILLED YEAR	COMPLETION DURING EARLY W/FLOOD	OFFTAKE RATE* BF/D		NEW WELL	COMPLETION	OFFTAKE RATE** BF/D
622 AREA							
608	1950	OPEN HOLE NITRO	77		621	PERF, ACIDIZED	100
613	1974	PERF, ACIDIZED	300		622	PERF, ACIDIZED	250
604	1949	OPEN HOLE NITRO	600				
713 AREA							
706	1969	PERF, ACIDIZED	150		713	PERF, ACIDIZED	15
609	1950	OPEN HOLE NITRO	77		623	PERF, ACIDIZED	100
					620	PERF, ACIDIZED	80
629 AREA							
601	1948	OPEN HOLE NITRO	300		629	PERF, ACIDIZED	150
712 AREA							
614	1974	PERF, ACIDIZED	250		712	PERF, ACIDIZED	250
702 AREA							
702	1948	OPEN HOLE, ACIDIZED	150		702	OPEN HOLE, ACIDIZED	60
705	1948	OPEN HOLE, ACIDIZED	150		705	OPEN HOLE, ACIDIZED	300
					710	PERF, ACIDIZED	100
					715	PERF, ACIDIZED	75

** rate observed for upper San Andres during early w/flood*
*** rate observed for upper San Andres during CO2 flood*

11/04/1999 NEW_REENTERED_AFE_VS_ACTUAL

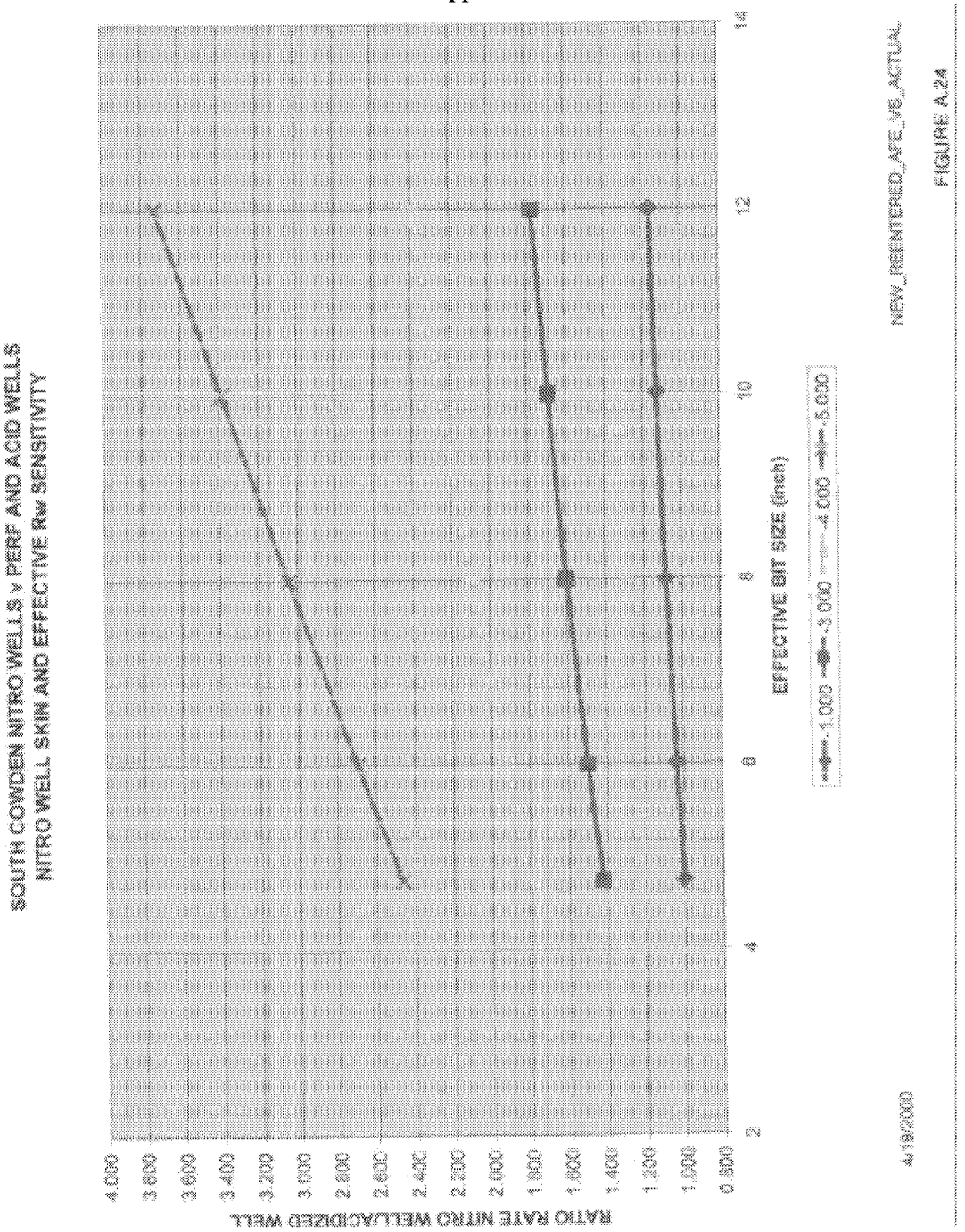
FIGURE A.32

SOUTH COWDEN CALIPER MEASUREMENTS
CALIPER SURVEY POST NITRO SHOOT

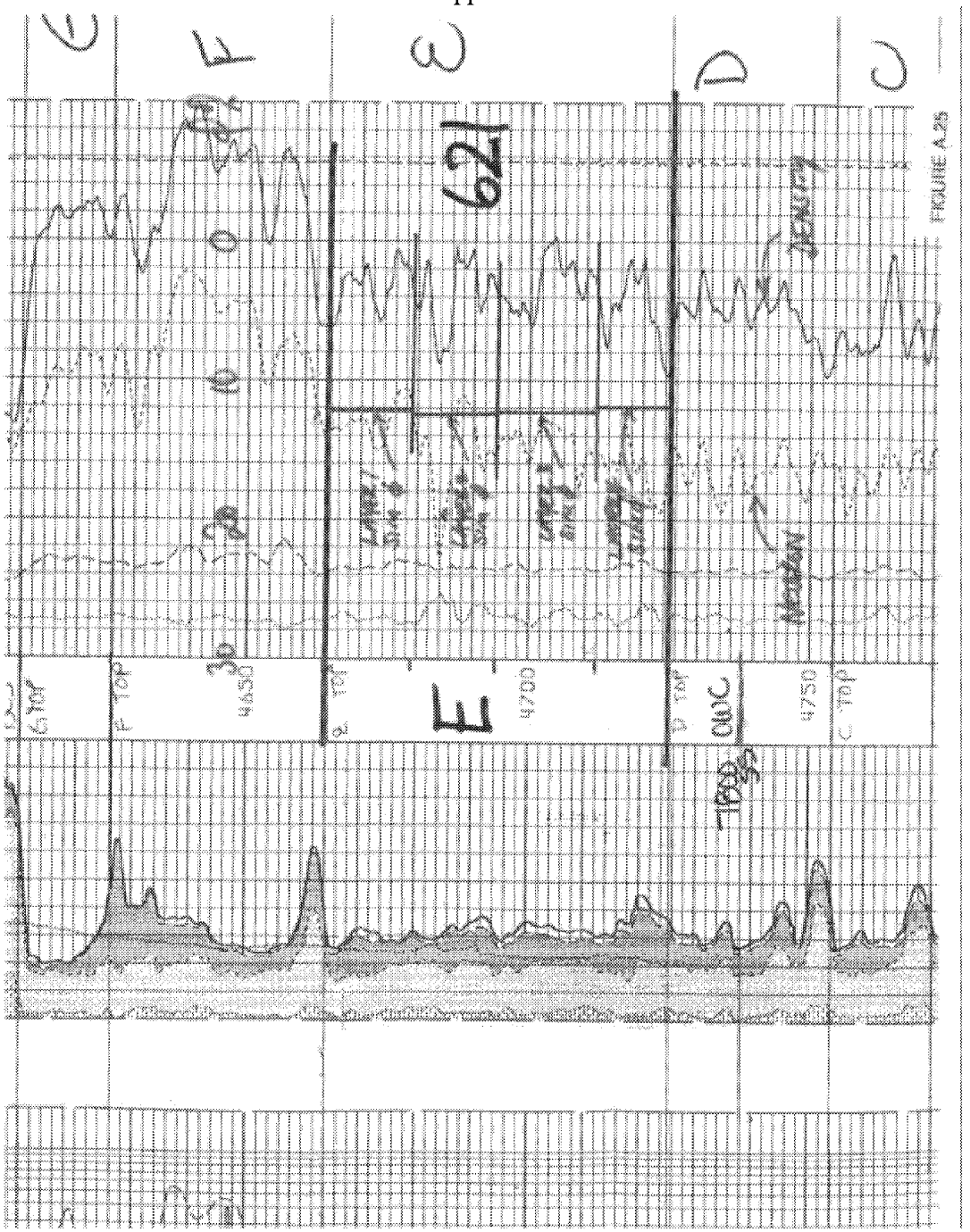
WELL	ORIGINAL BIT SIZE INCHES	MIN HOLE INCHES	MAX HOLE INCHES	AVE HOLE INCHES
202	4.875	6	10	7
206	5	6	14.5	7.5
601	4.75	7.5	11.25	10
602	6.5	5.75	7.75	7
603	4.875	5.5	14	9
605	4.75	7	12	9
606	4.75	4.75	6	5
608	4.75	5.5	15	9
609	4.75	5	14	6
610	4.875	5.5	7	6
610	4.875	5	16	6

3/23/2009 NEW_REENTERED AFE VS ACTUAL

FIGURE A.23


SOUTH COWDEN NITRO WELLS v PERF AND ACID WELLS
NITRO WELL SKIN AND EFFECTIVE Rw SENSITIVITY
RATIO RATE NITRO WELL/ACIDIZED WELL
4.000
3.800
3.600
3.400
3.200
3.000
2.800
2.600
2.400
2.200
2.000
1.800
1.600
1.400
1.200
1.000
0.800
2
4
6
8
10
12
14
EFFECTIVE BIT SIZE (inch)
1.000
3.000
4.000
5.000
4/19/2000
NEW_REENTERED_AFE_VS_ACTUAL
FIGURE A.24

Appendix G



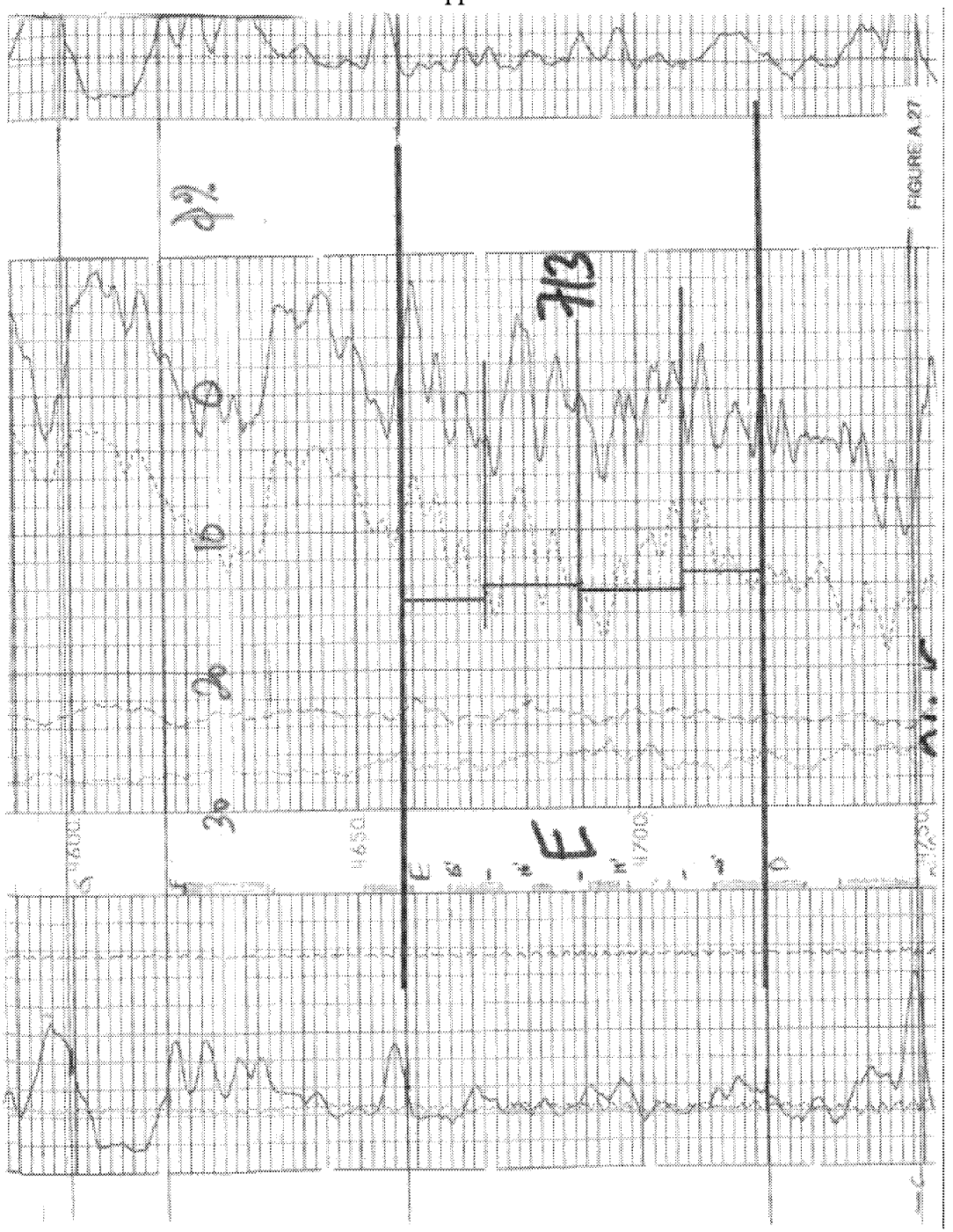
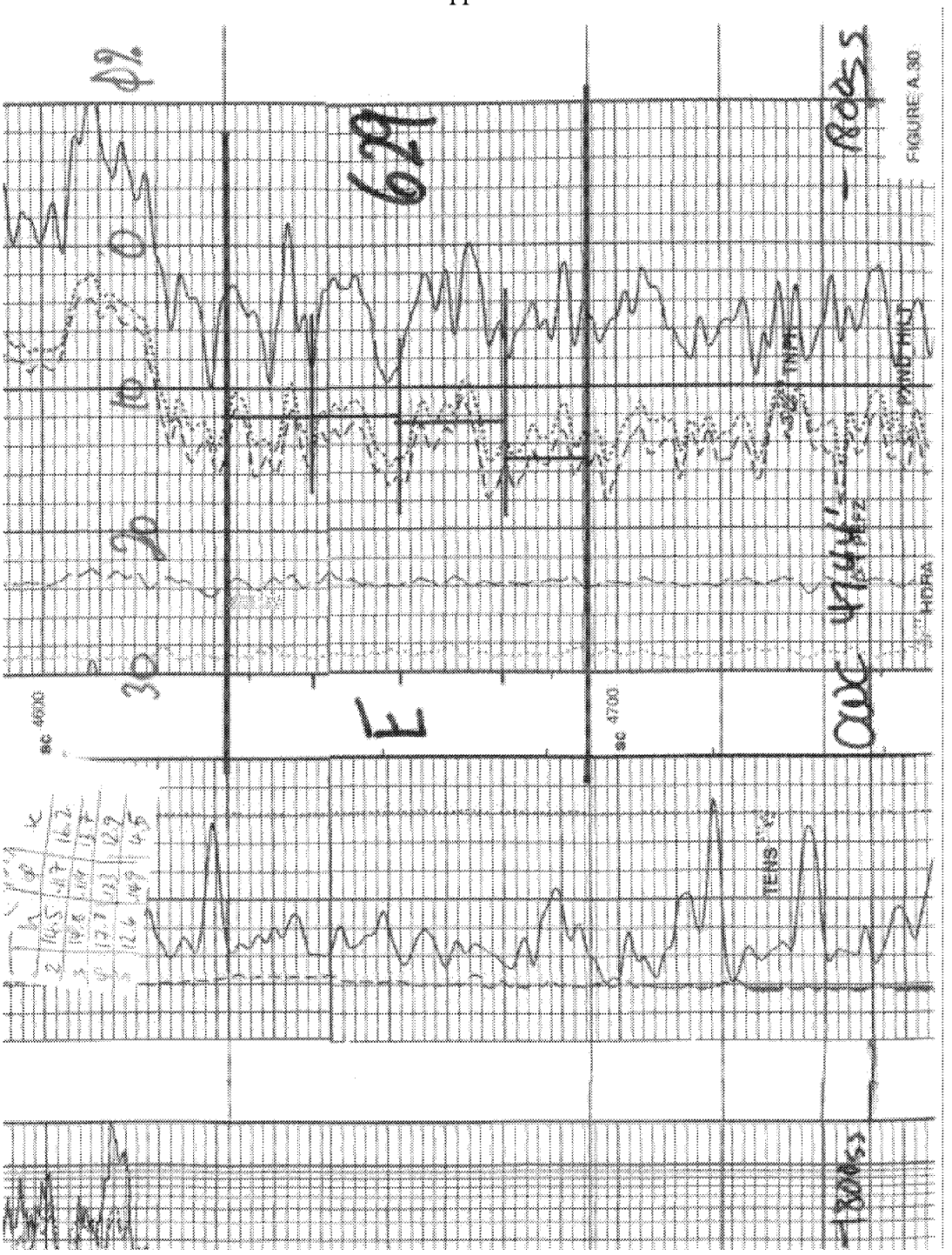


FIGURE A.27

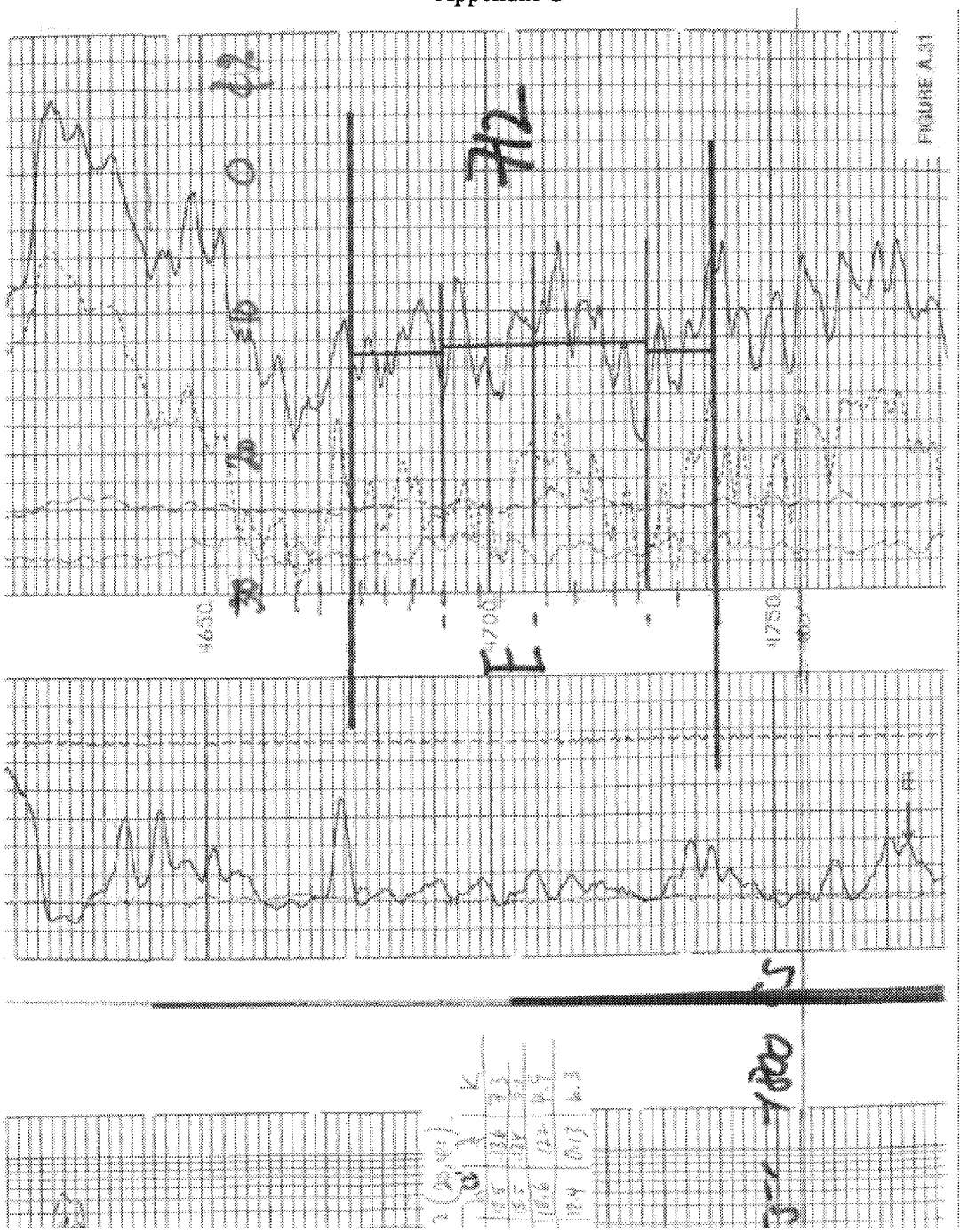
FIGURE A-28

FIGURE A.29
4500

Appendix G



Appendix G



Appendix G

Appendix G

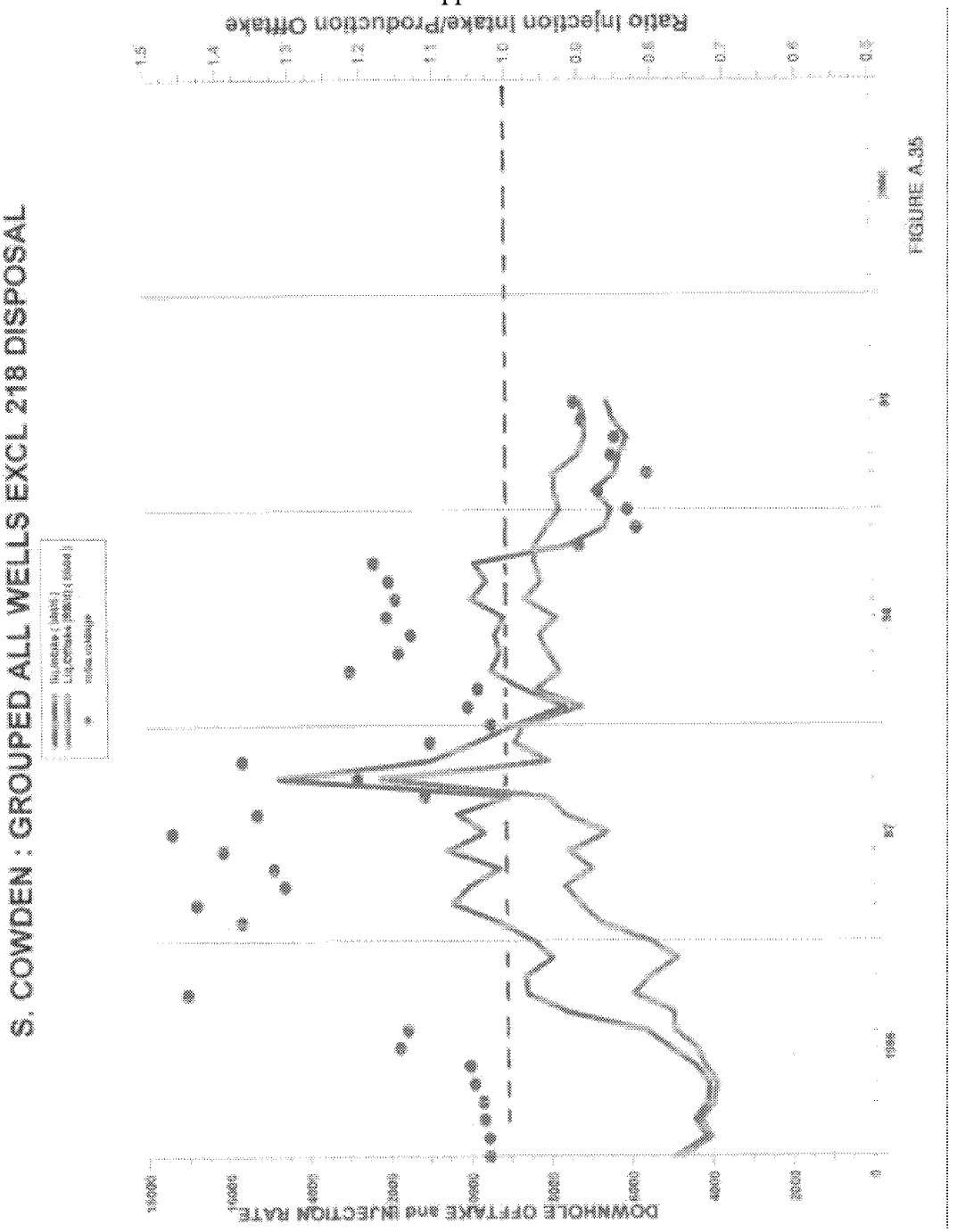
SOUTH COWDEN NEW WELL RESERVOIR QUALITY COMPARISON

WELL	AREA	ACTUAL	SIMULATION		SIMULATION POROSITY
		FLUID	FLUID		vs ACTUAL POROSITY
		BFPD	BFPD		
621	622	100	150	OPTIMISTIC	
622	622	250	150	OK	
713	713	15	250	OPTIMISTIC	
623	713	100	250	OK	
620	713	80	150	OPTIMISTIC	
629	629	150	240	OPTIMISTIC	
712	712	250	150	PESSIMISTIC	
710	702	100	n/a	OK	
718	702	75	250	PESSIMISTIC	

11/08/1999

NEW_CENTERED_AFE_VS_ACTUAL

FIGURE A-34


S. COWDEN : GROUPED ALL WELLS EXCL 218 DISPOSAL
Ratio Injection Intake/Production Offtake
DOWNHOLE OFFTAKE and INJECTION RATE
FIGURE A.35

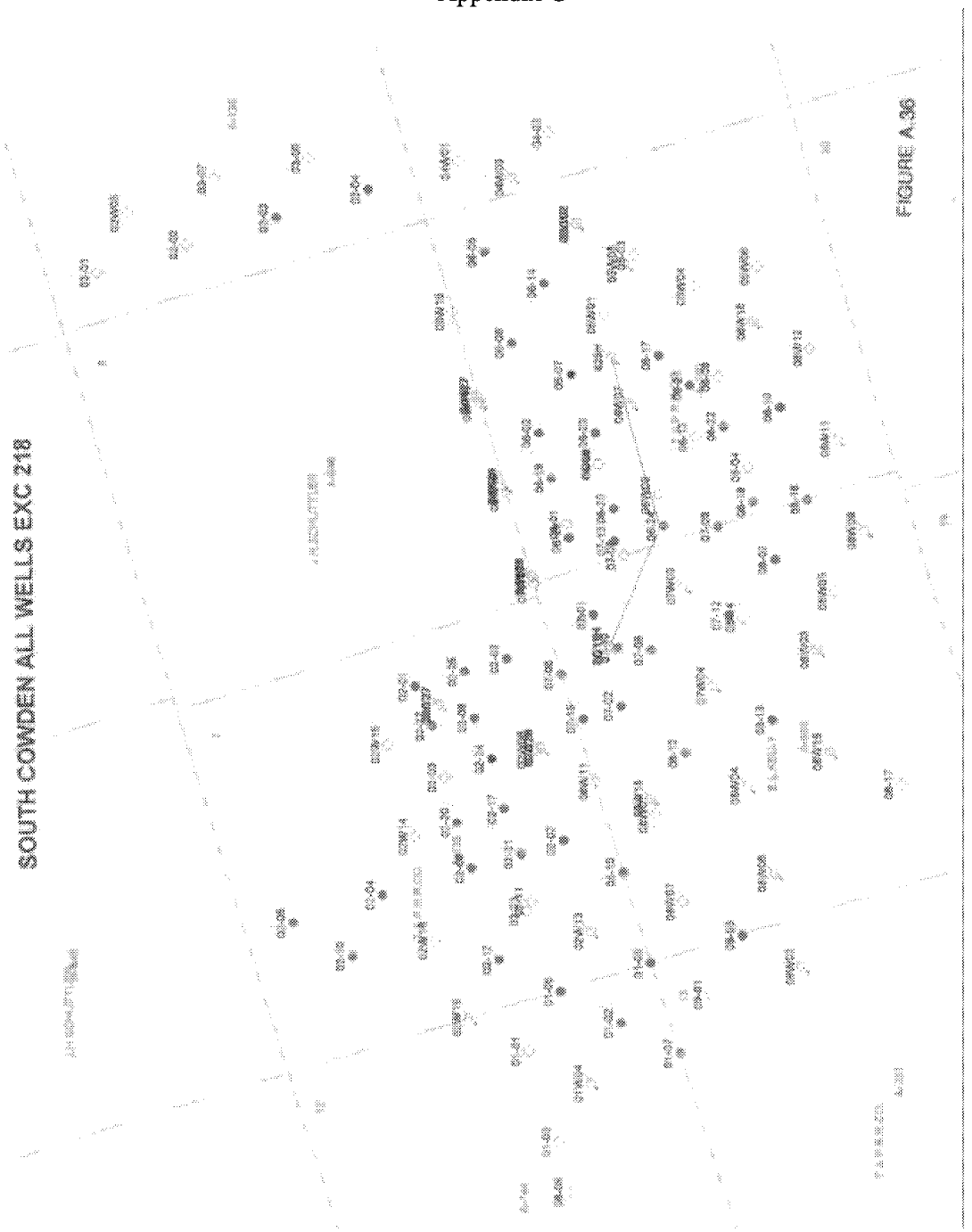


FIGURE A.36

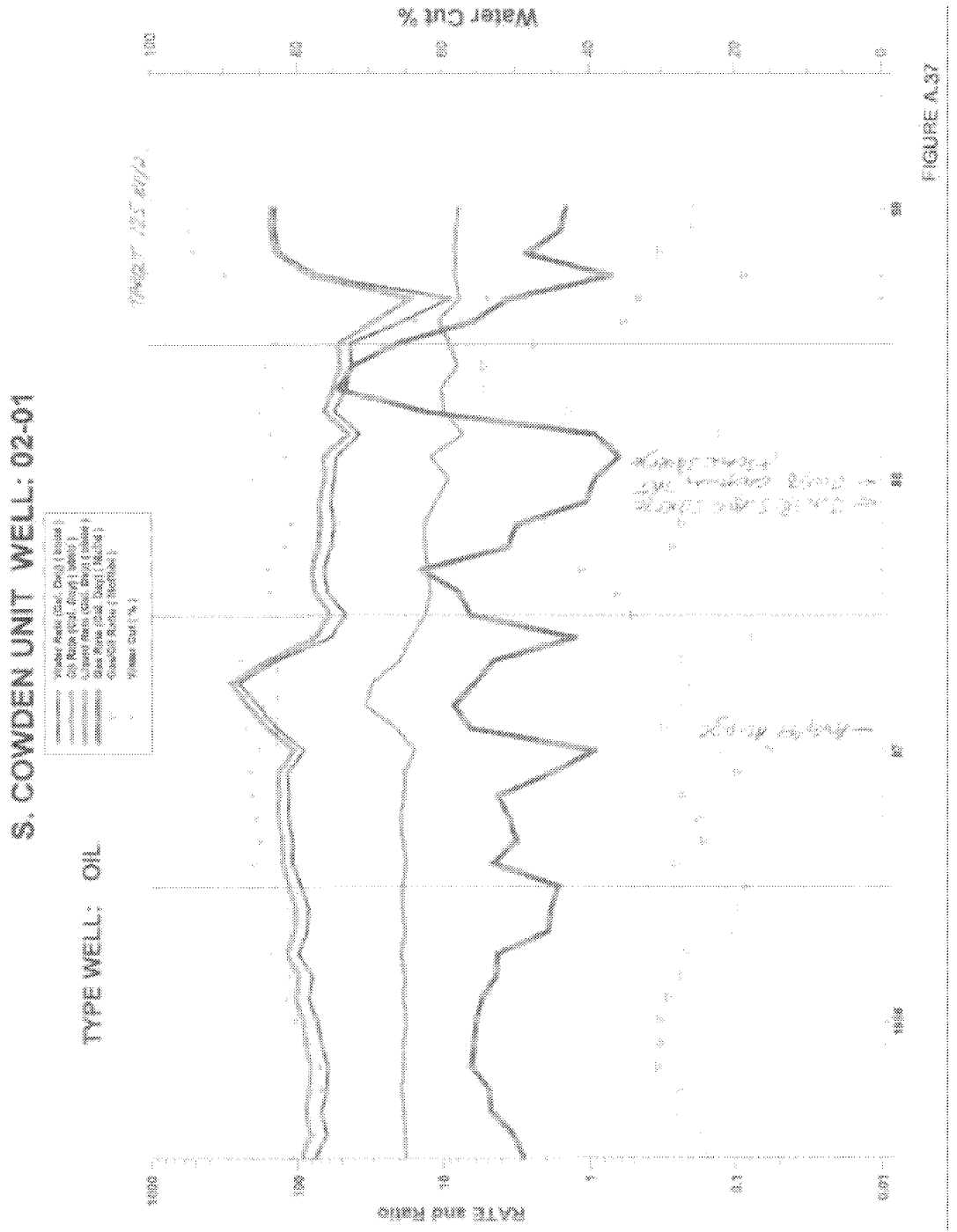

S. COWDEN UNIT WELL: 02-01
TYPE WELL: OIL
Water Cut %
RATE and Ratio
100
80
60
40
20
0
1000
100
10
1
0.1
0.01

FIGURE A.37

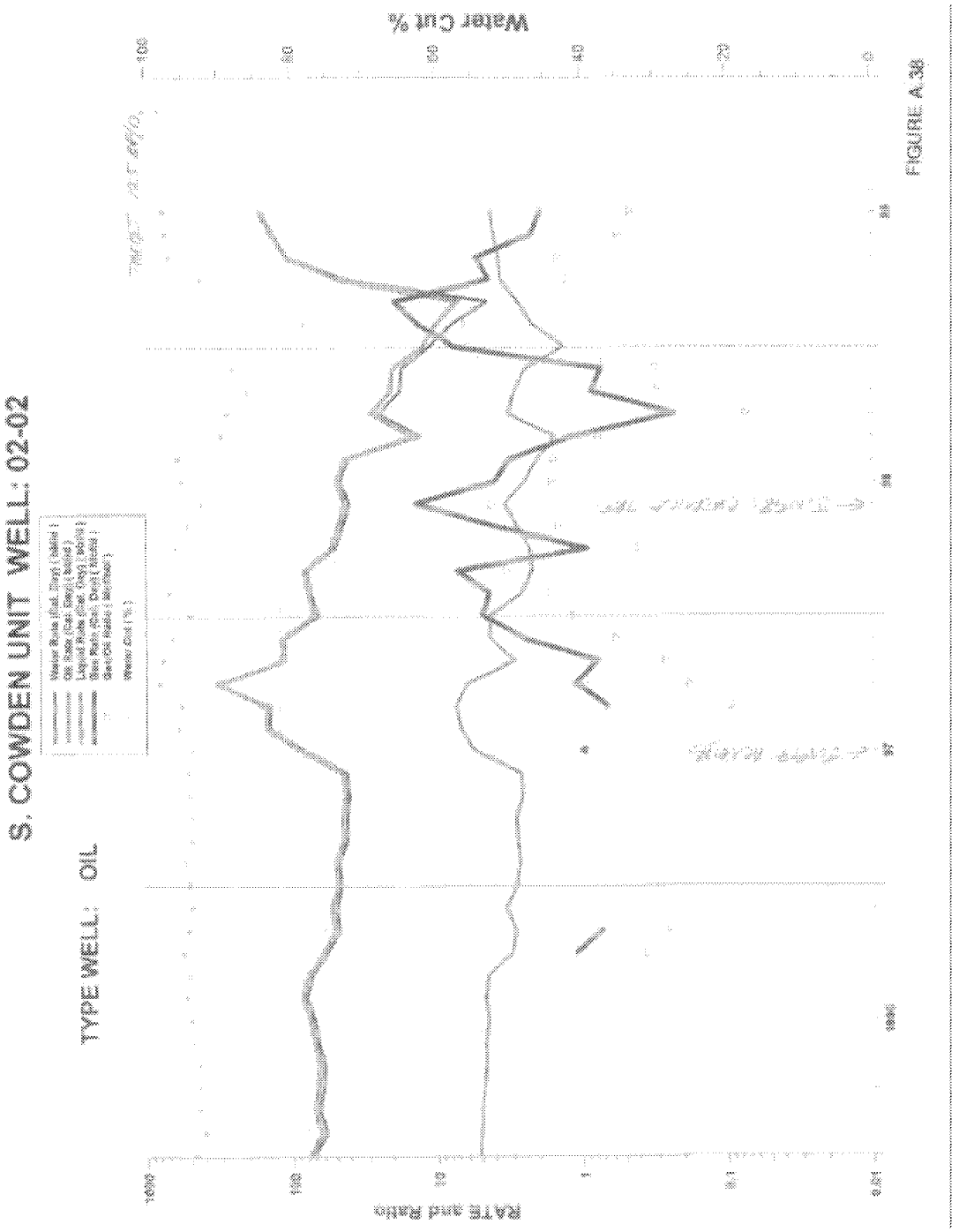
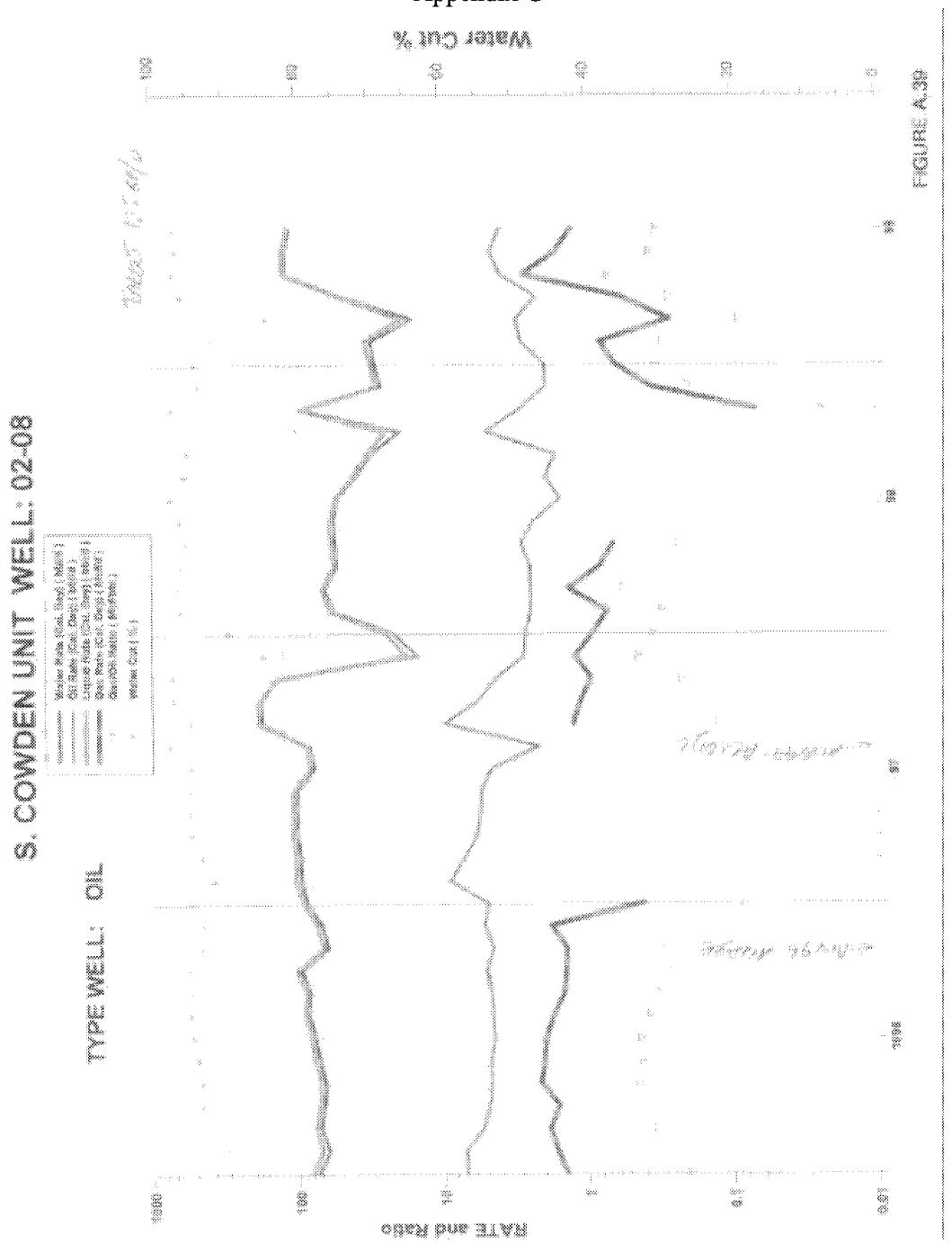
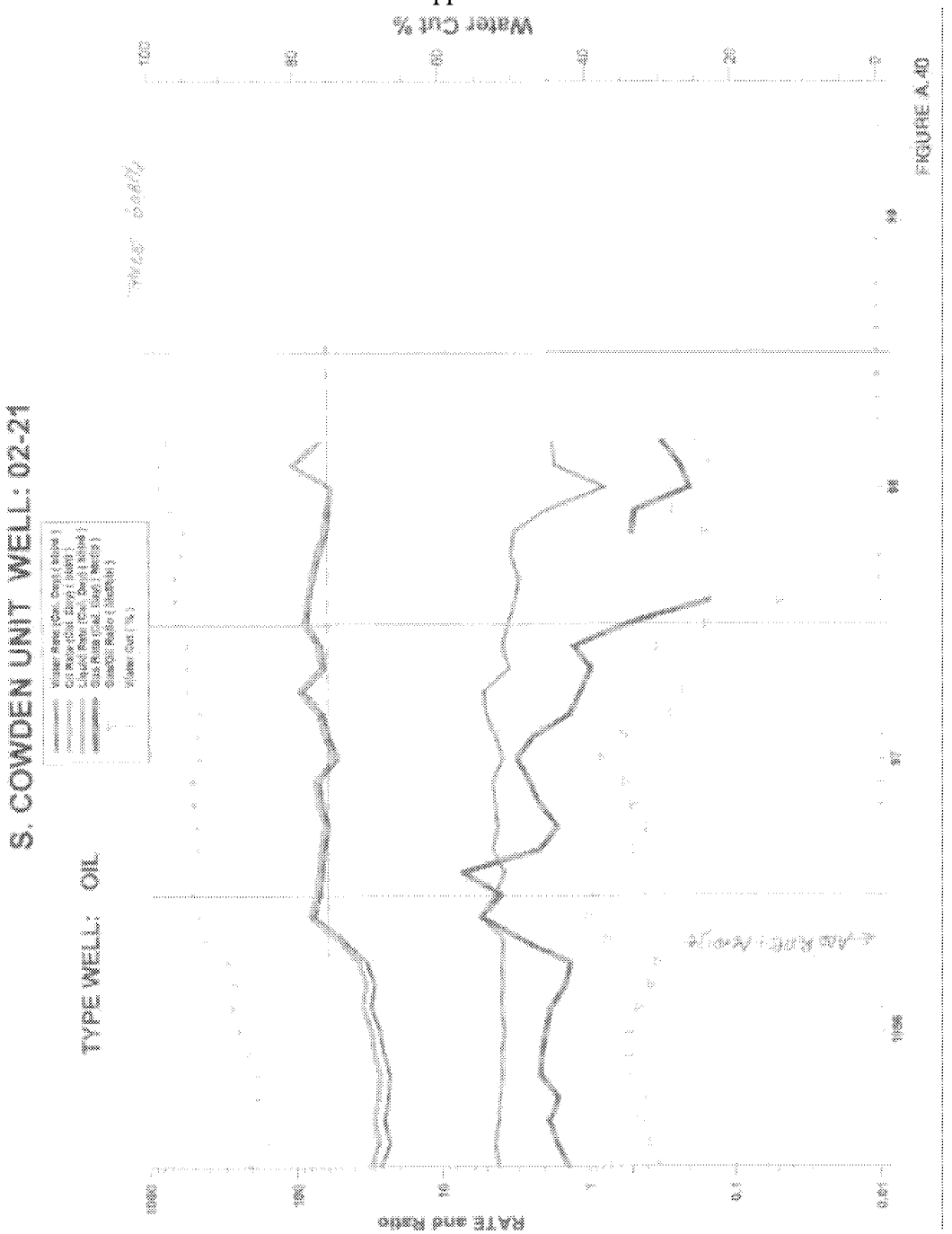

S. COWDEN UNIT WELL: 02-02
TYPE WELL: OIL
RATE and Ratio
Water Cut %
100
10
1
0.1
0.01
100
80
60
40
20
0

FIGURE A.38


S. COWDEN UNIT WELL: 02-08
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A.39


S. COWDEN UNIT WELL: 02-21
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A.40

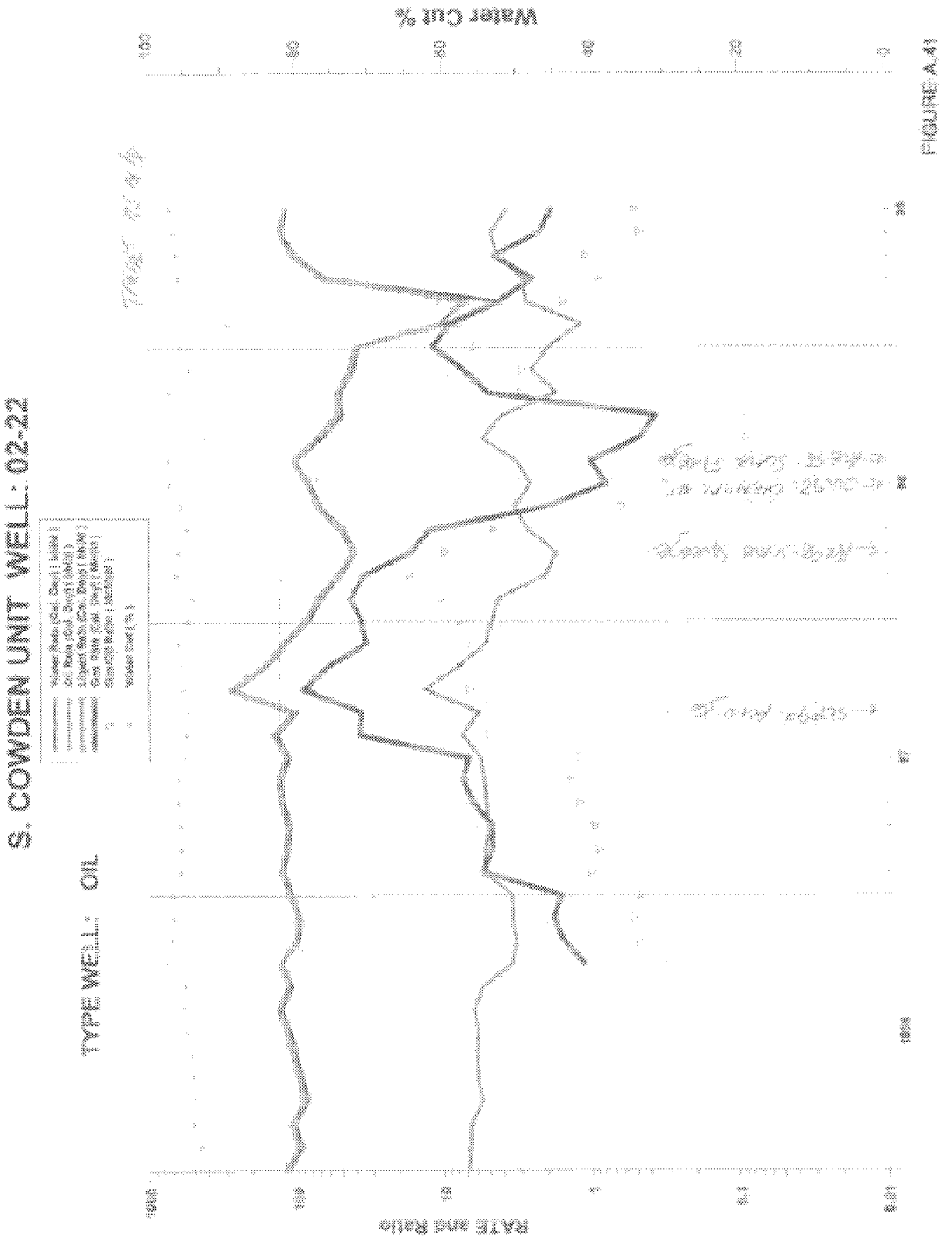

S. COWDEN UNIT WELL: 02-22
TYPE WELL: OIL
Water Cut %
RATE and Ratio

FIGURE A.41

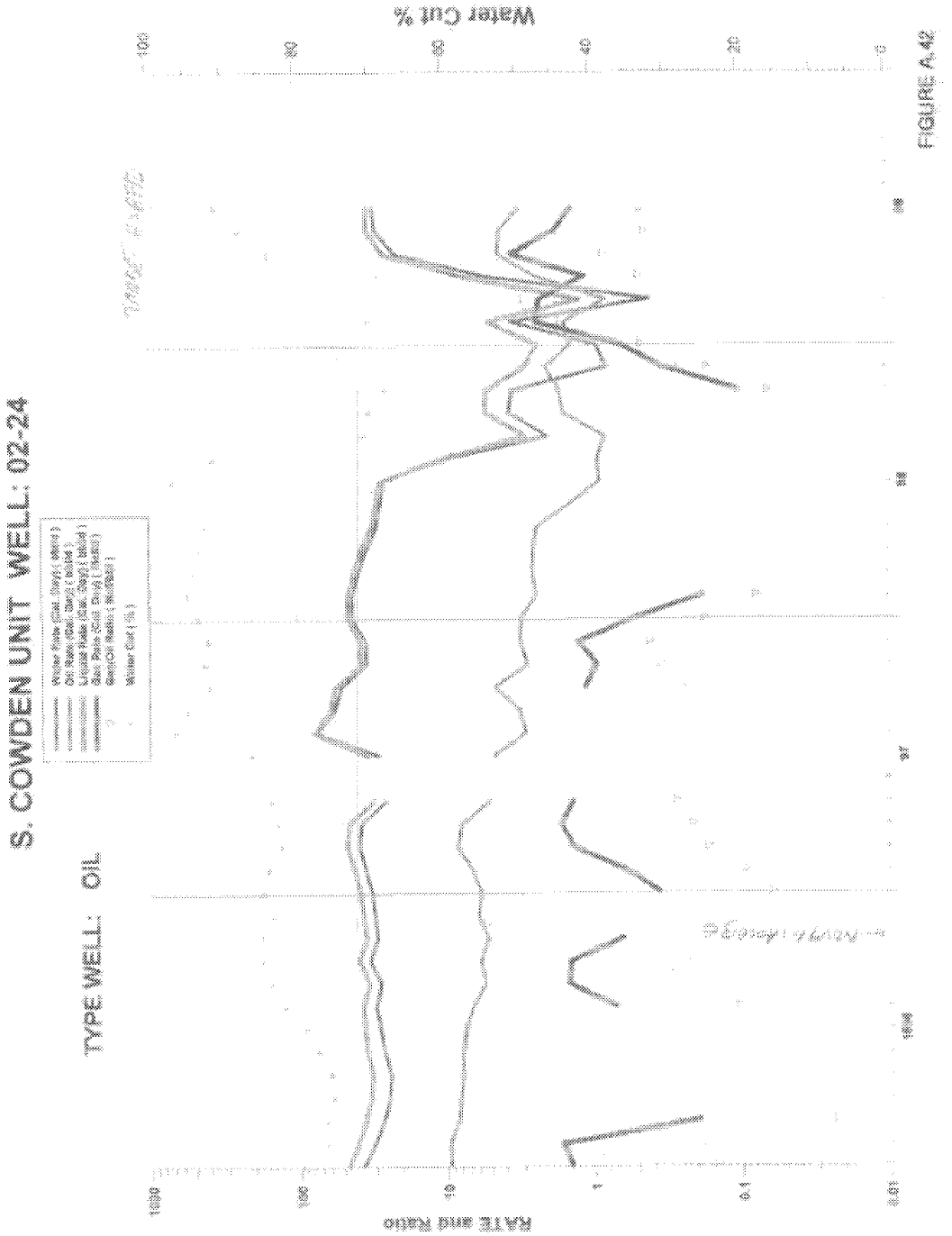

S. COWDEN UNIT WELL: 02-24
TYPE WELL: OIL
Water Cut %
RATE and Ratio

FIGURE A.42

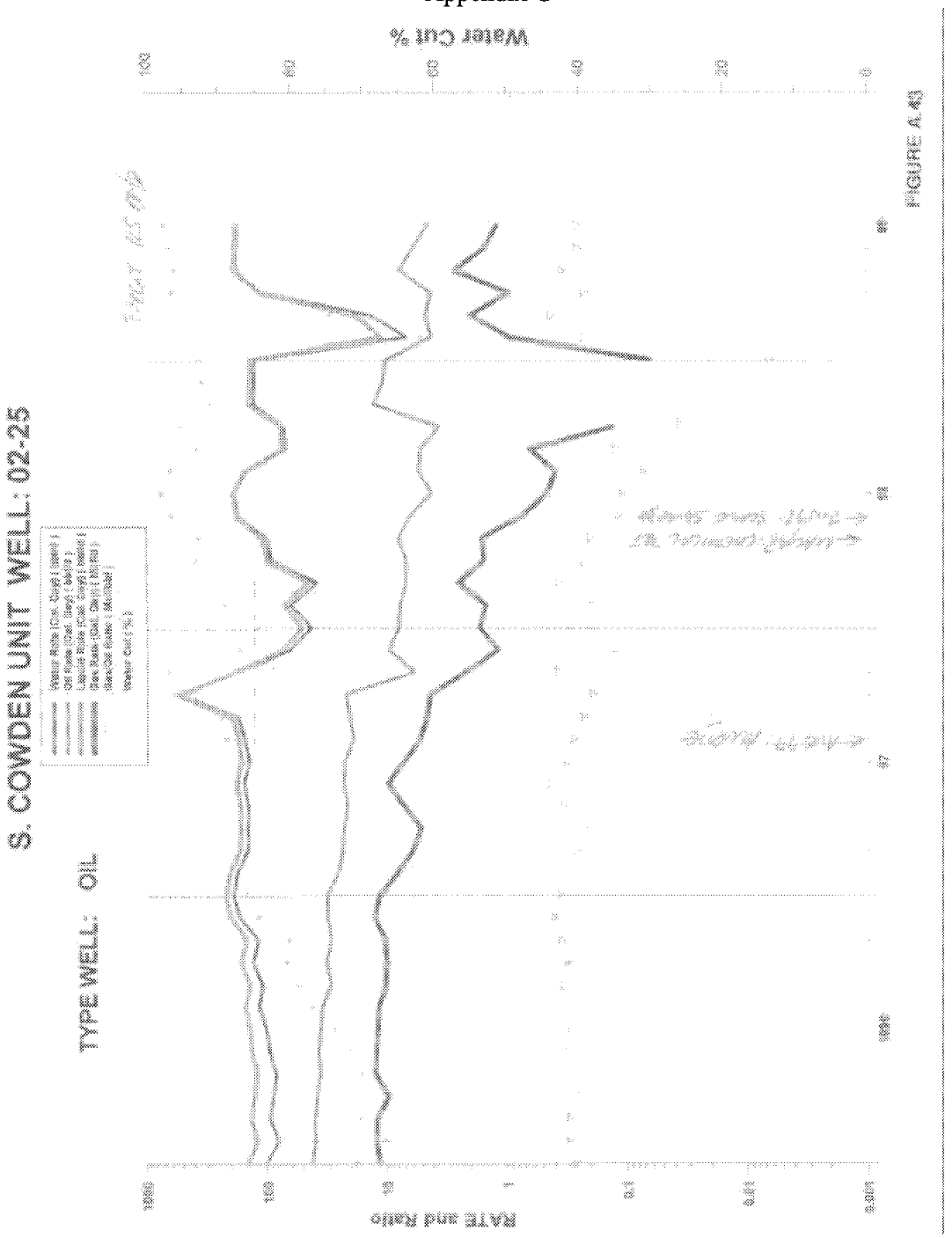
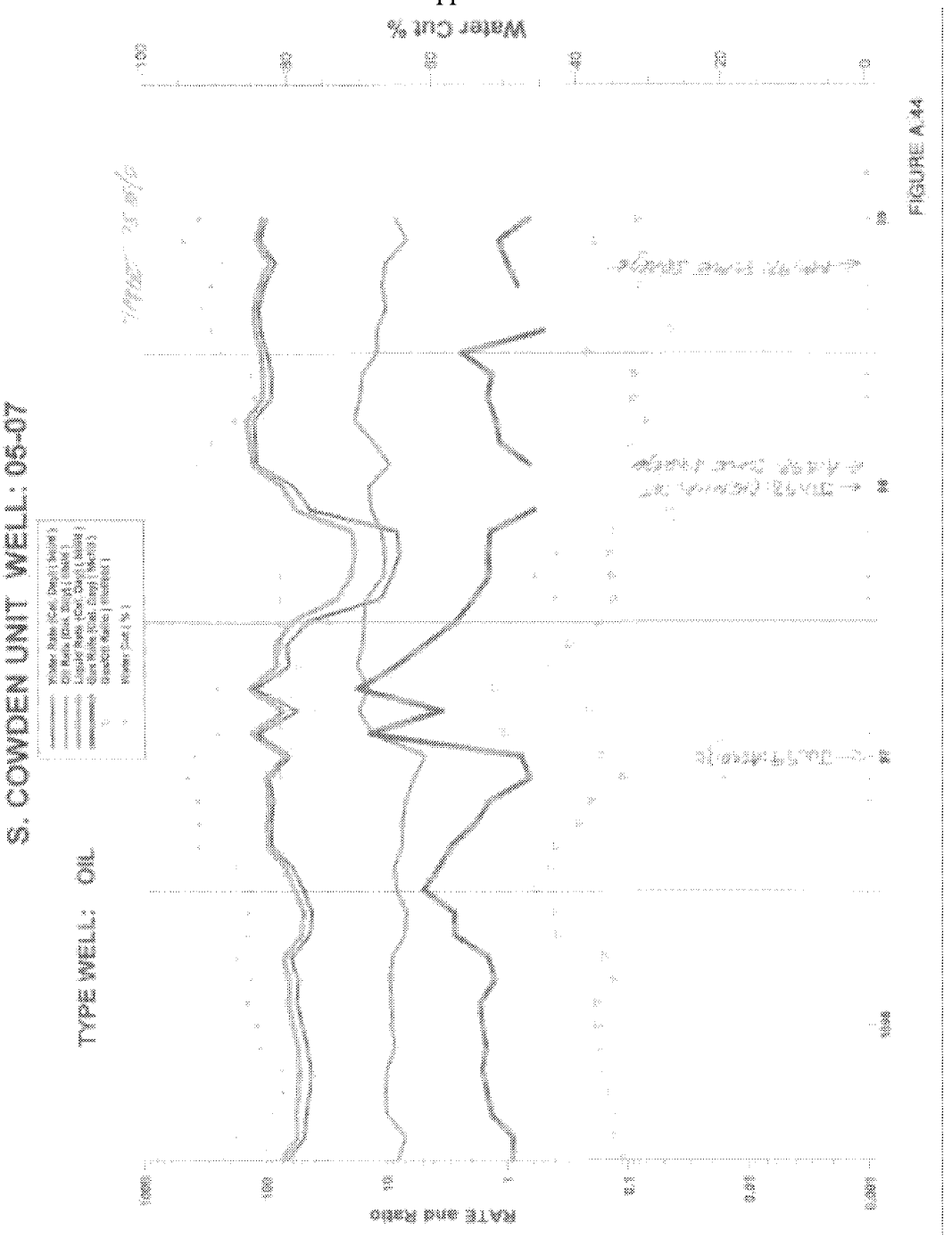
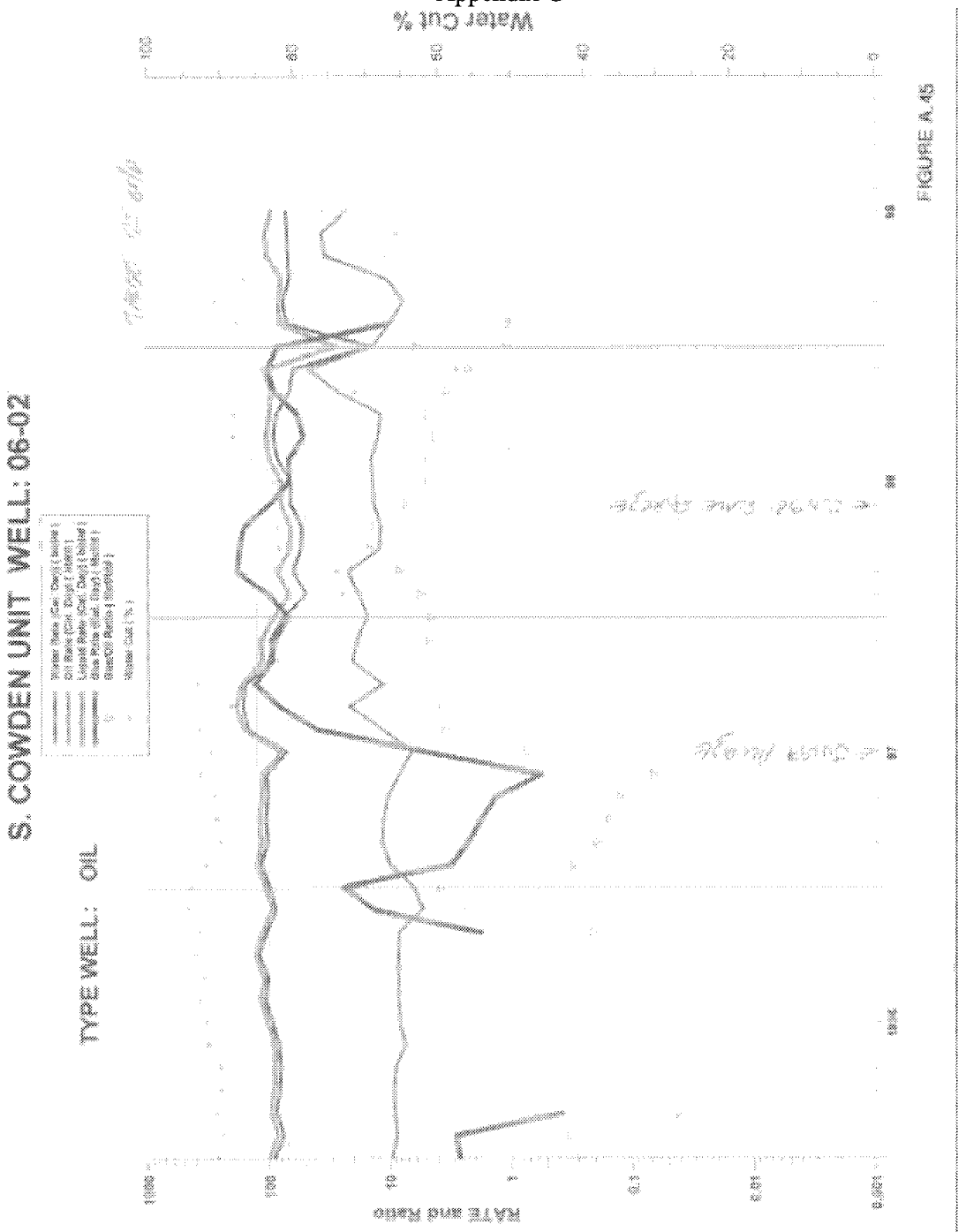

S. COWDEN UNIT WELL: 02-25
TYPE WELL: OIL
RATE and Ratio
Water Cut %

FIGURE A.43


S, COWDEN UNIT WELL: 05-07
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A.44


S. COWDEN UNIT WELL: 06-02
TYPE WELL: OIL
Water Cut %
RATE and RATIO
FIGURE A.45

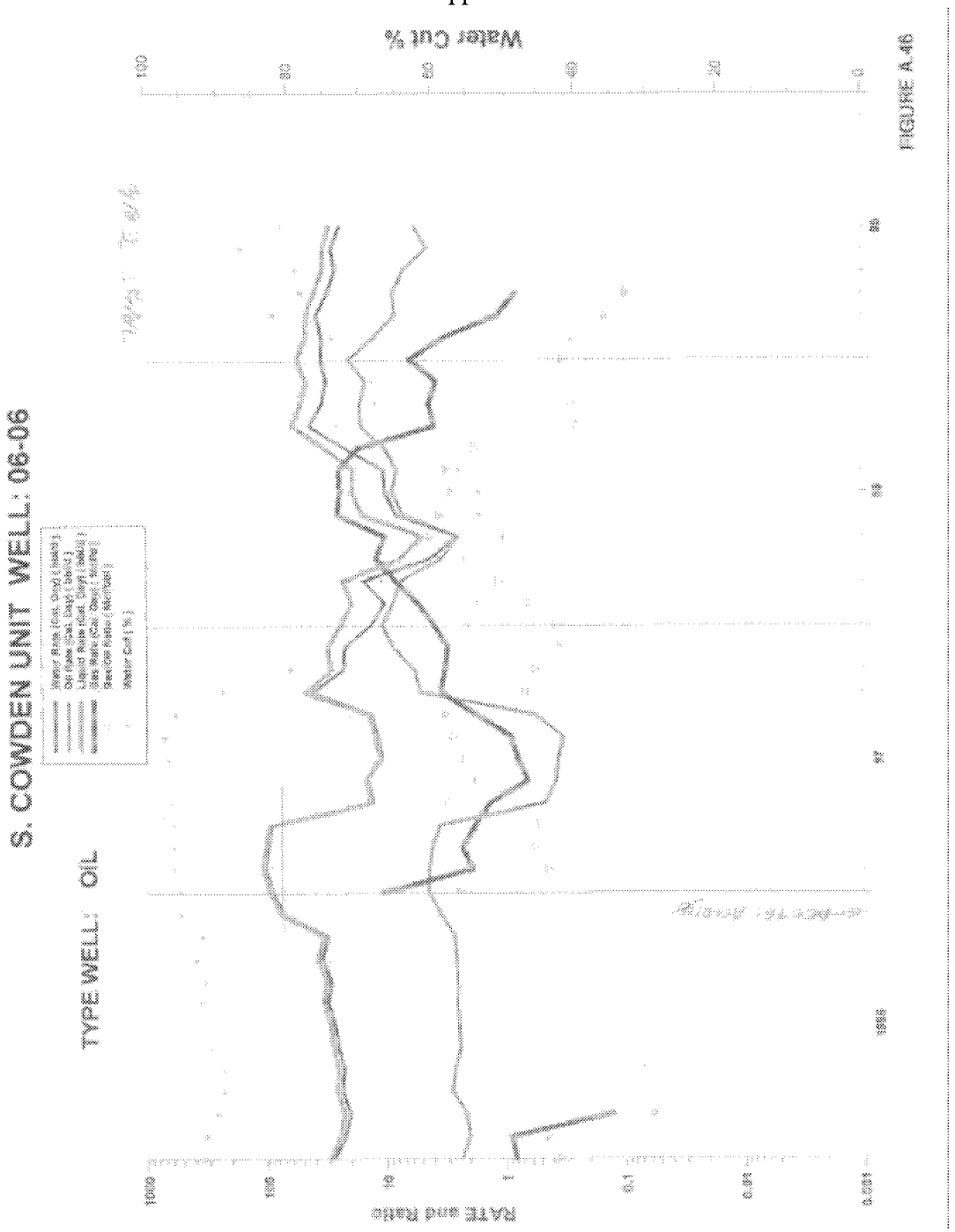
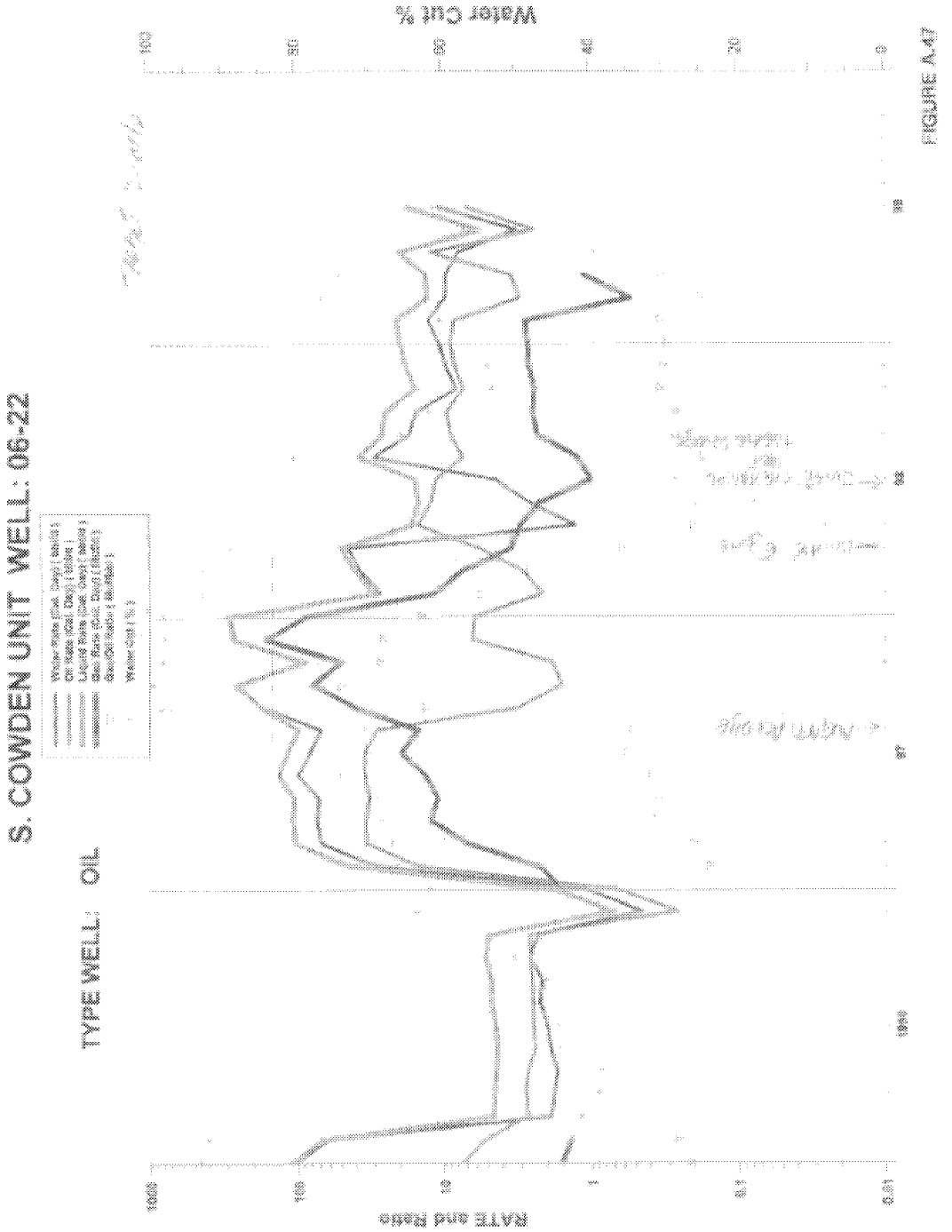

S. COWDEN UNIT WELL: 06-06
TYPE WELL: OIL
Water Cut %
RATE and Ratio
100
80
60
40
20
0
1000
100
10
1
0.1
0.01
0.001

FIGURE A.46


S. COWDEN UNIT WELL: 06-22
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A.47

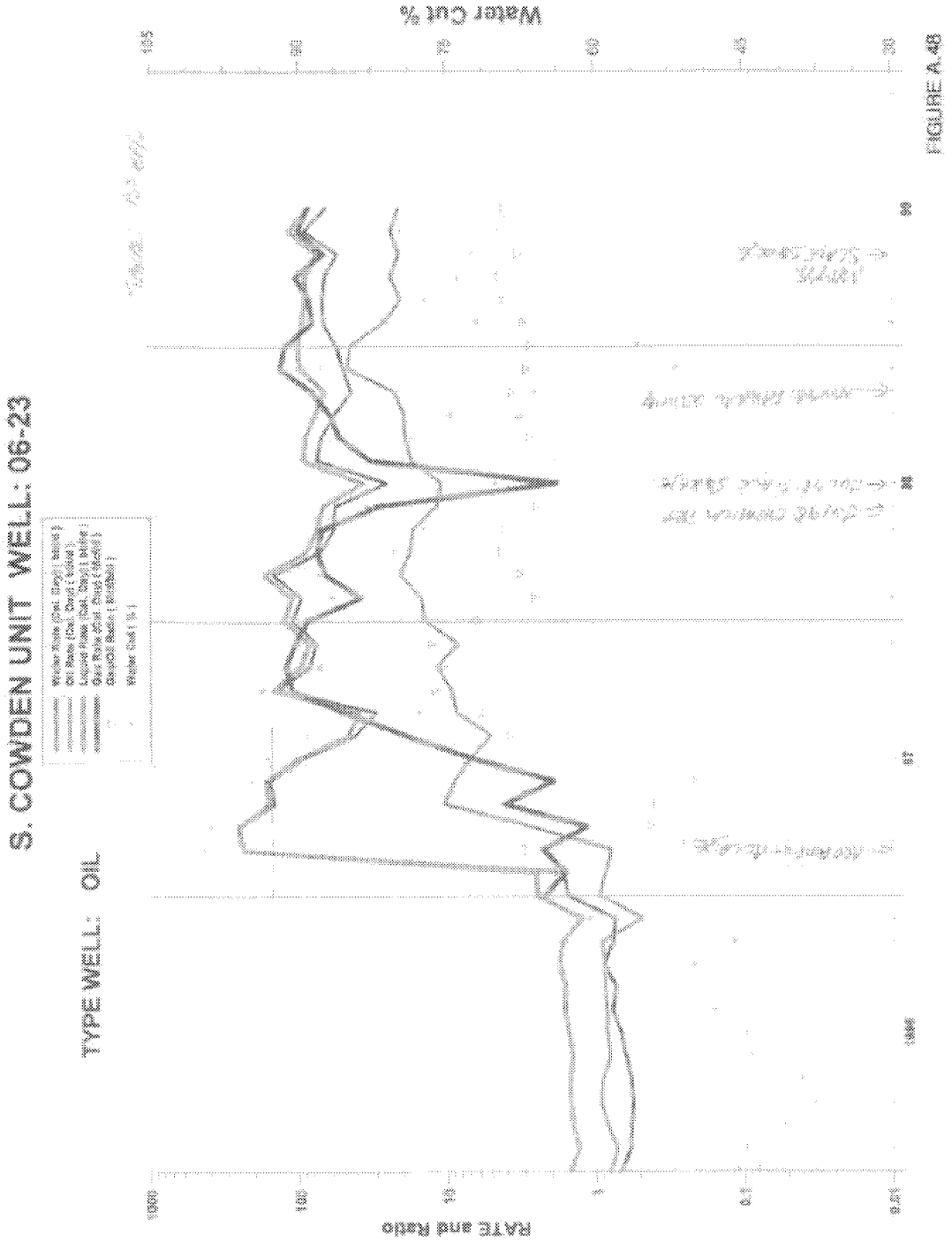
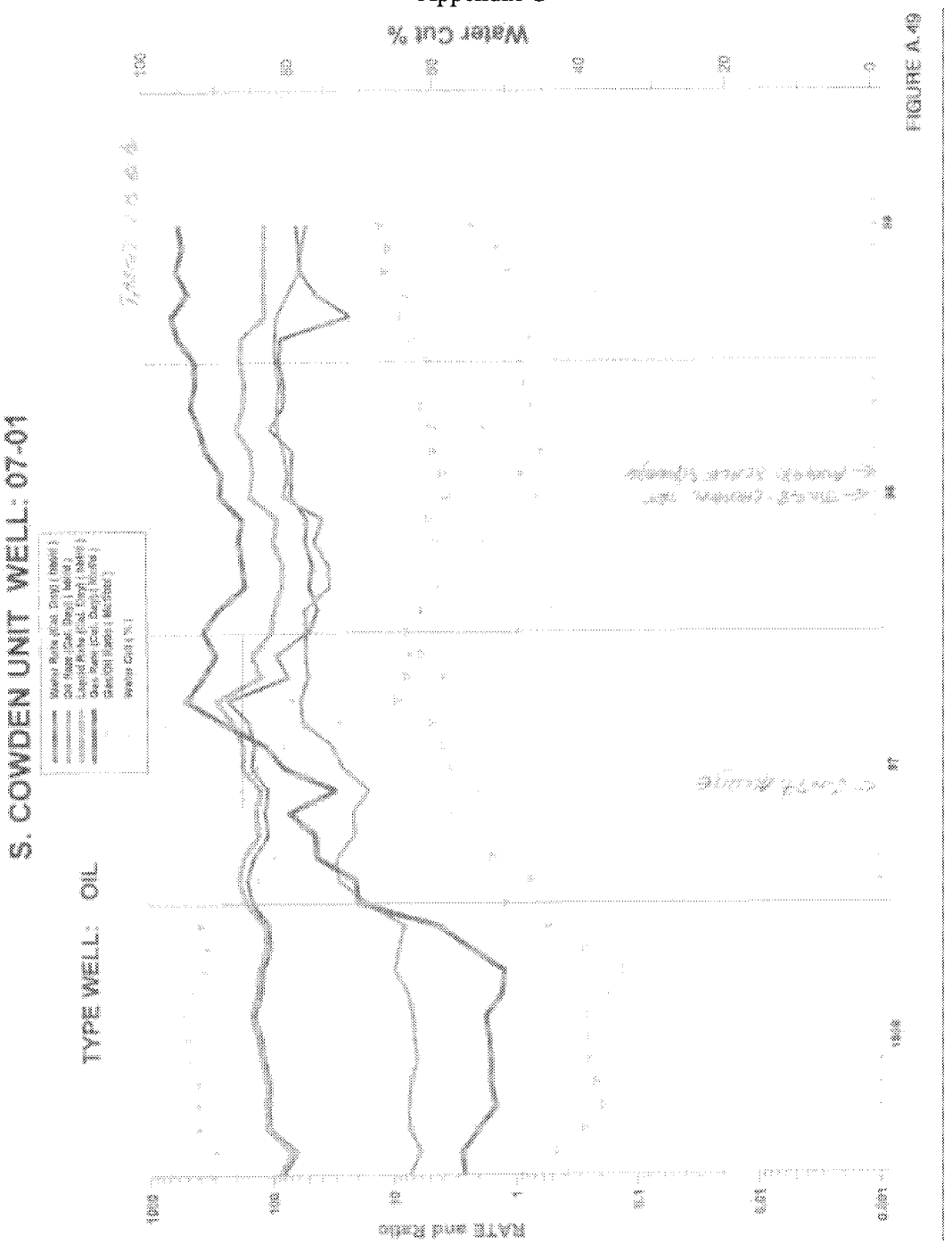
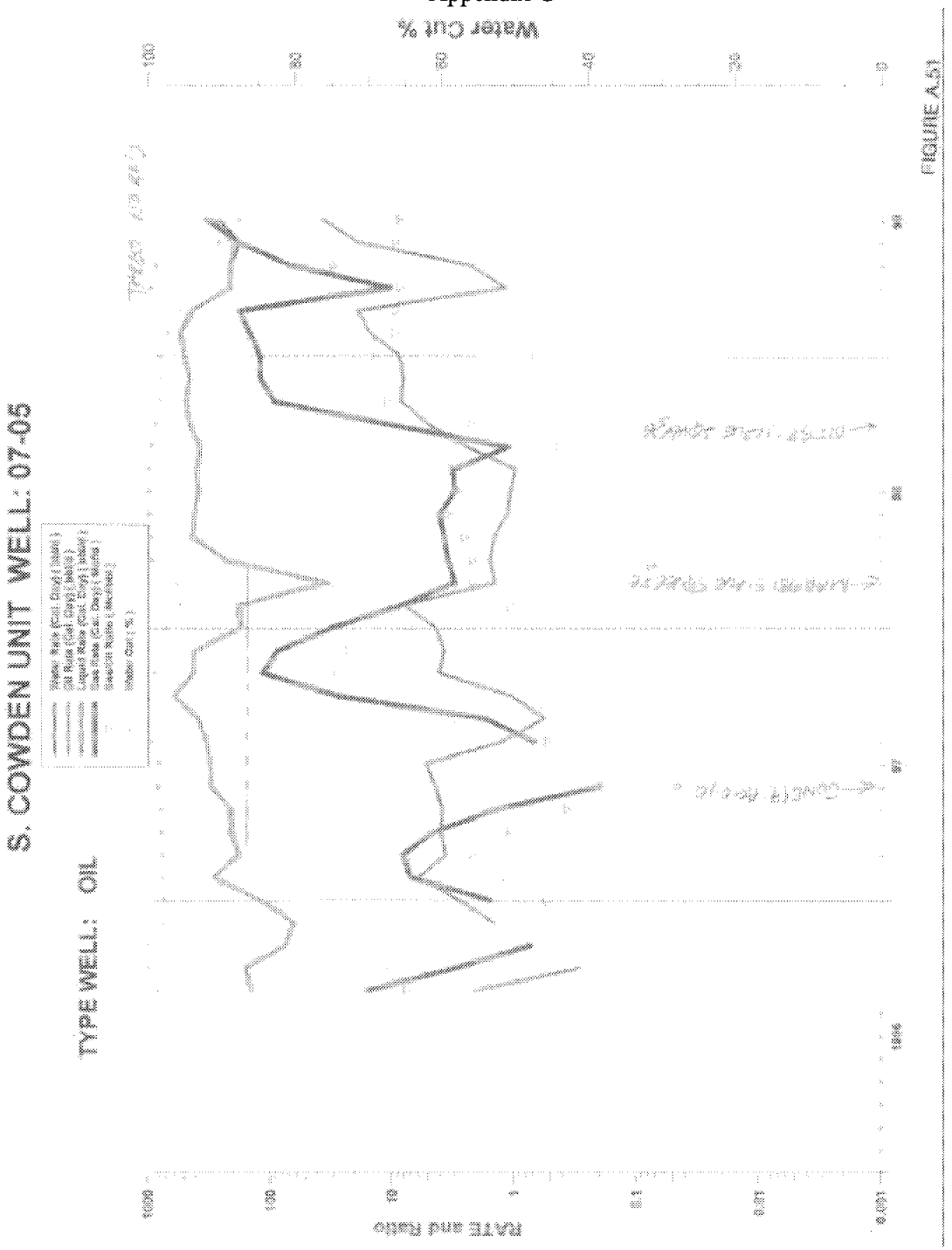

S. COWDEN UNIT WELL: 06-23
TYPE WELL: OIL
RATE and Ratio
Water Cut %

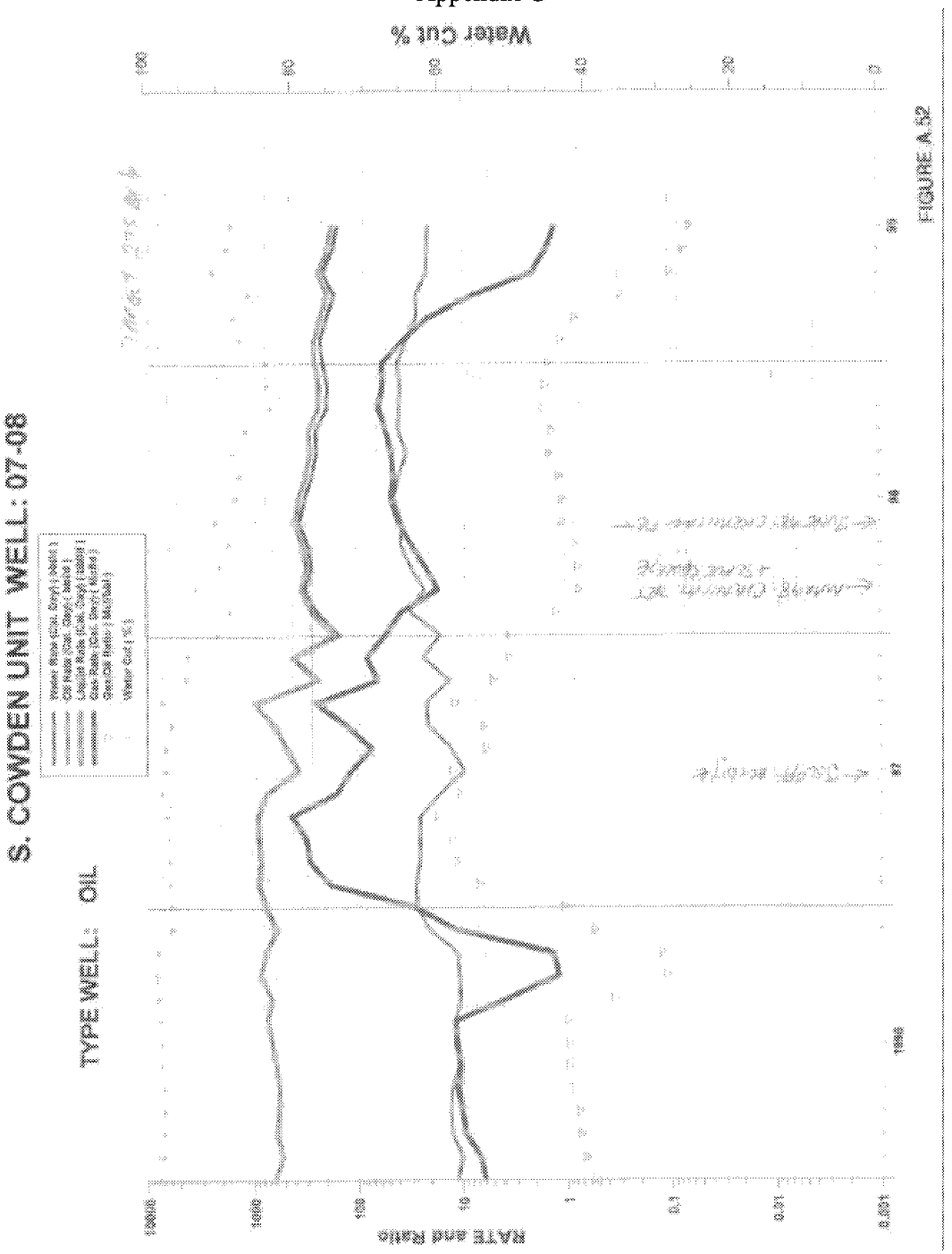
FIGURE A.48

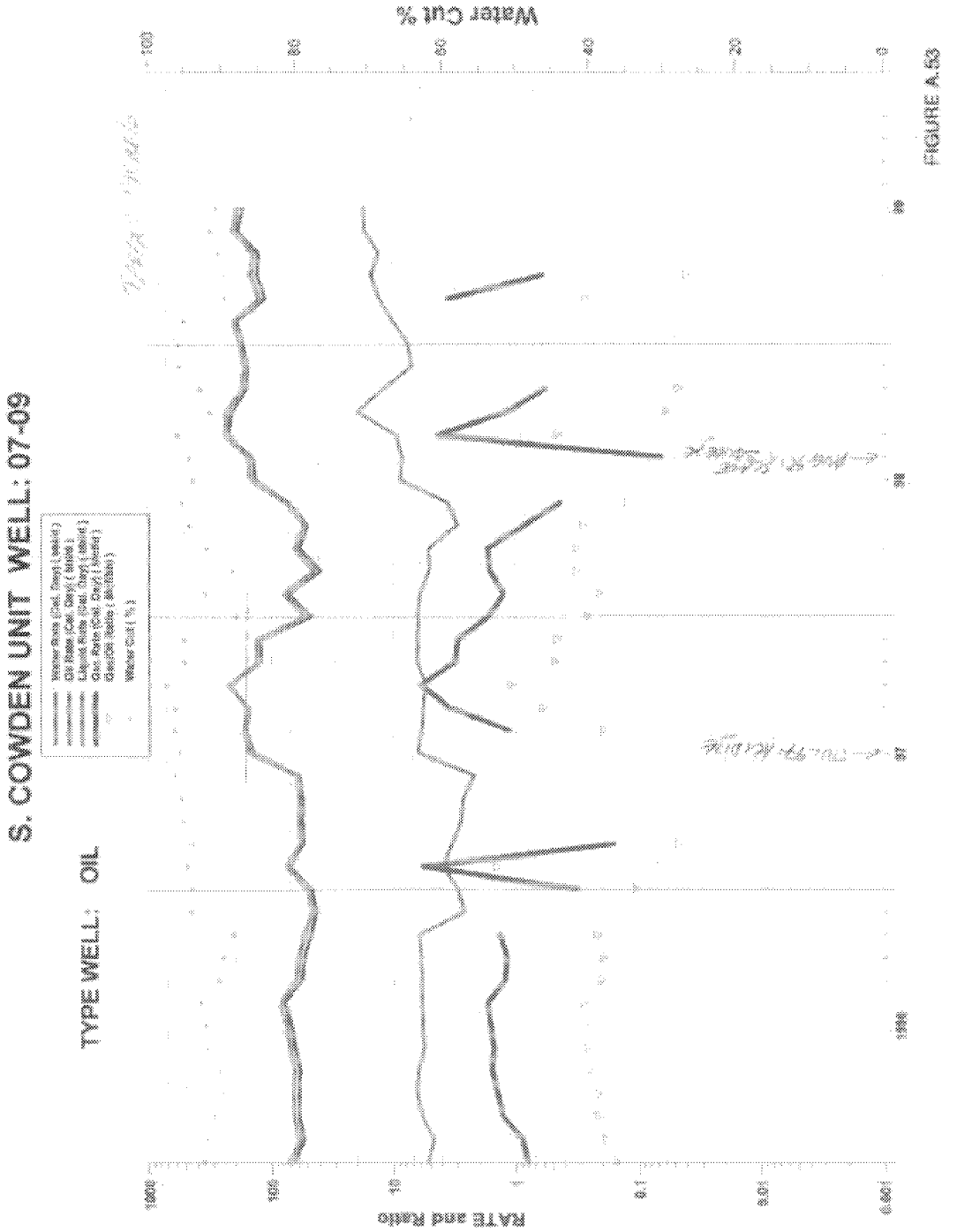

S. COWDEN UNIT WELL: 07-01
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A.49

S. COWDEN UNIT WELL: 07-02
TYPE WELL: OIL
RATE and Ratio
Water Cut %

FIGURE A.50


S. COWDEN UNIT WELL: 07-05
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A-51


S. COWDEN UNIT WELL: 07-08
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A.52


S. COWDEN UNIT WELL: 07-09
TYPE WELL: OIL
Water Cut %
RATE and Ratio
FIGURE A.53

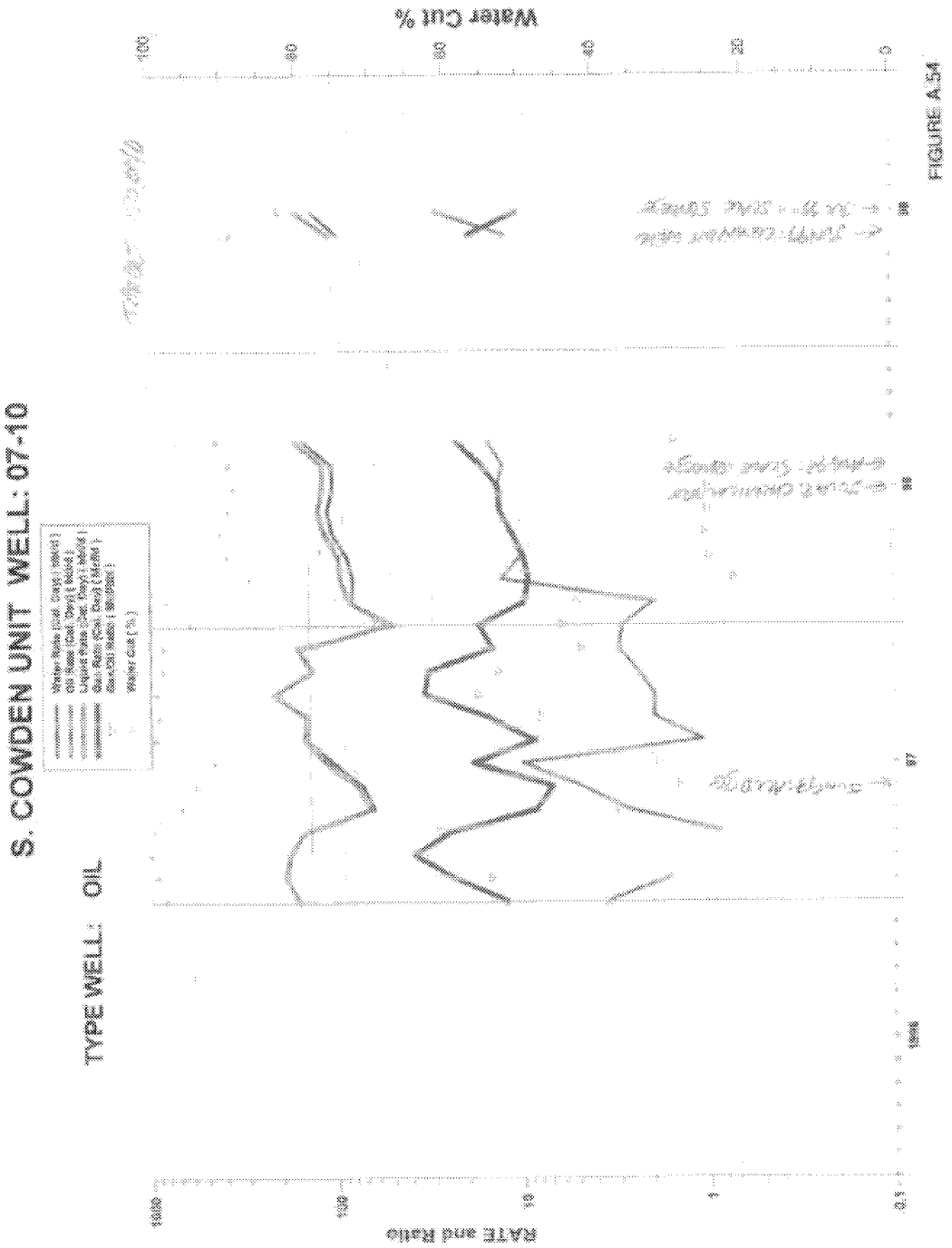

S. COWDEN UNIT WELL: 07-10
TYPE WELL: OIL
RATE and Ratio
Water Cut %
1000
100
10
1
0.1
100
80
60
40
20
0
1988
87
88

FIGURE A.54

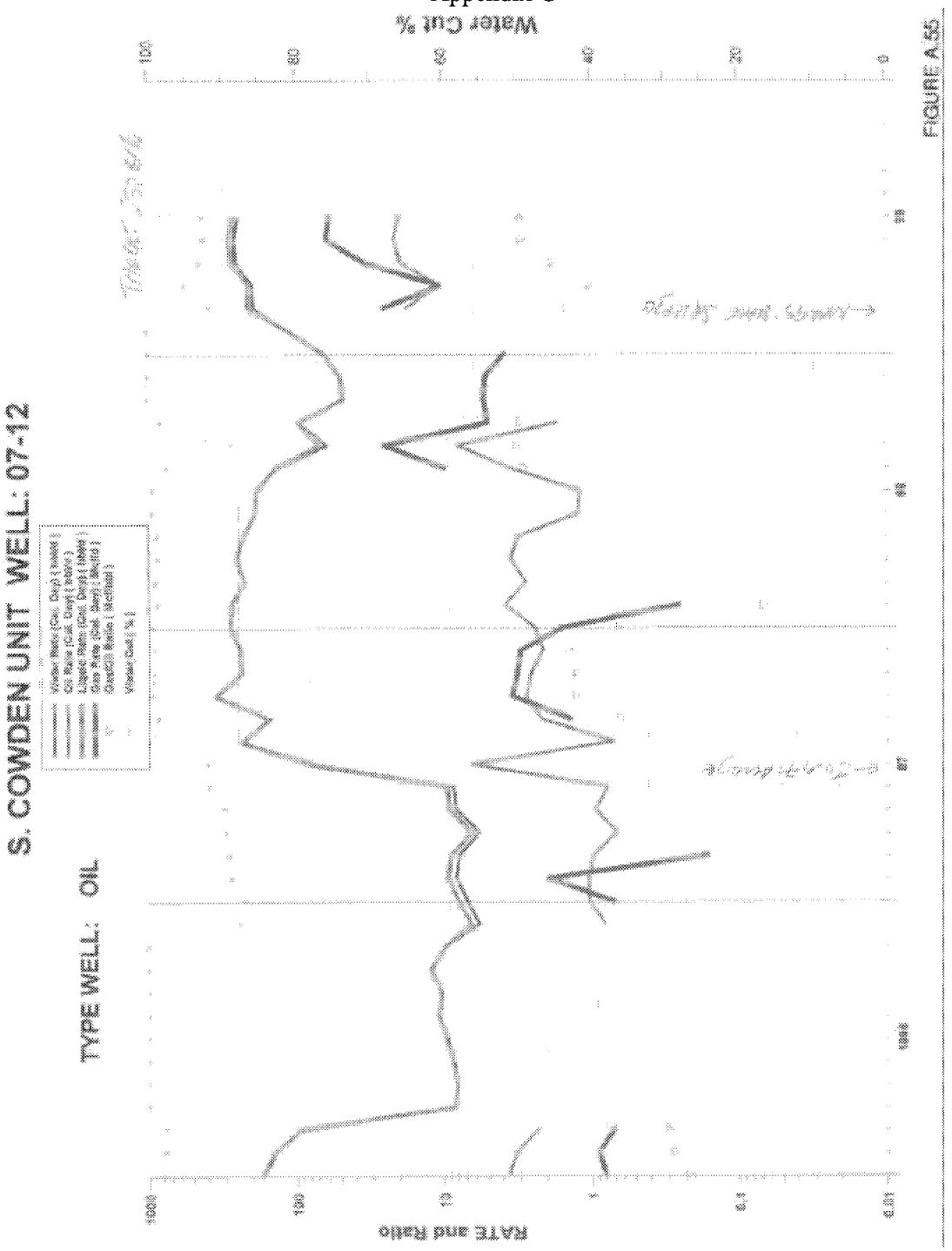

S. COWDEN UNIT WELL: 07-12
TYPE WELL: OIL
RATE and Ratio
Water Cut %

FIGURE A.55

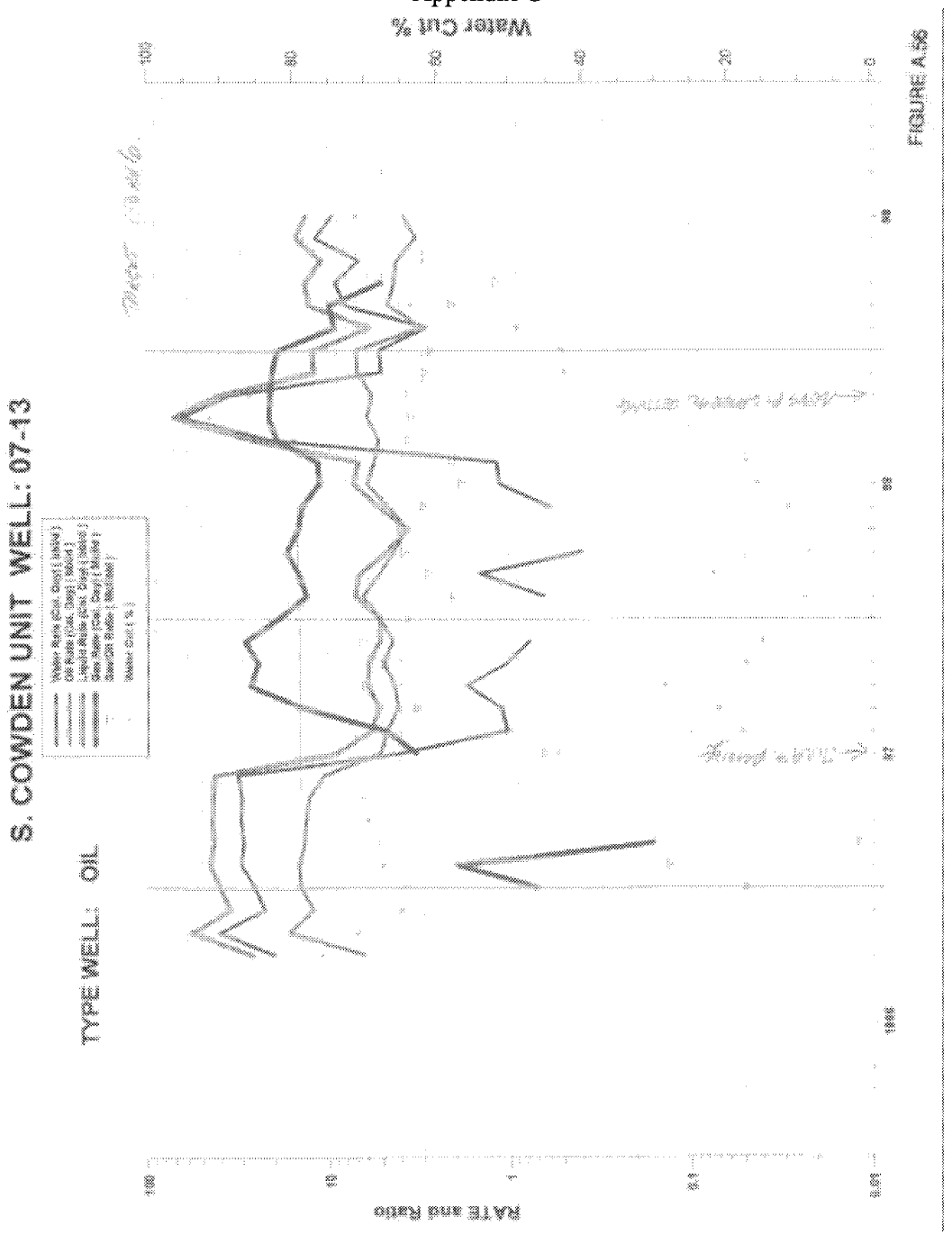
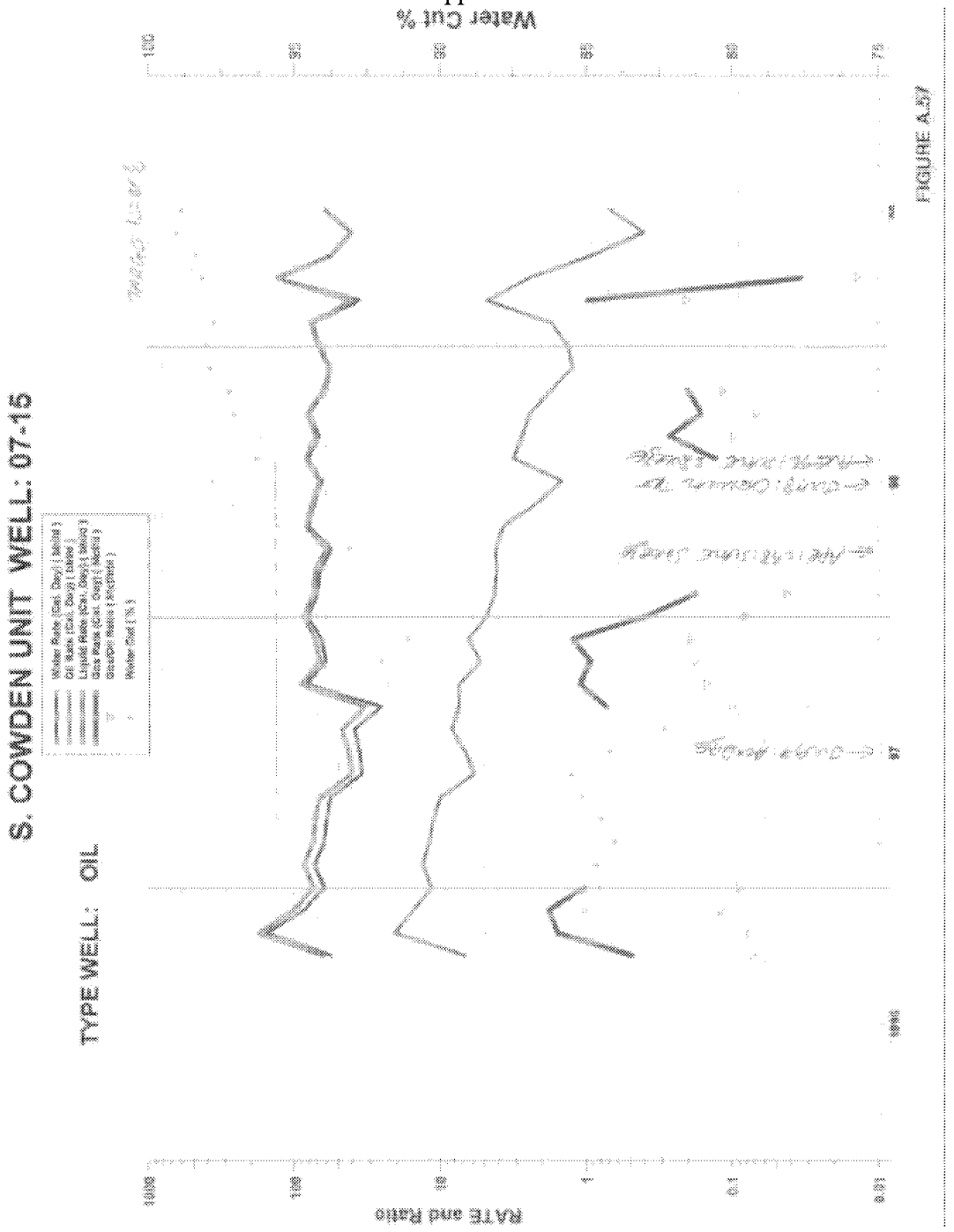

S. COWDEN UNIT WELL: 07-13
TYPE WELL: OIL
Water Cut %
RATE and Ratio
100
80
60
40
20
0
100
10
1
0.1
0.01
1996
97
98
99
00

FIGURE A.56


S. COWDEN UNIT WELL: 07-15
TYPE WELL: OIL
RATE and Ratio
Water Cut %
FIGURE A.57

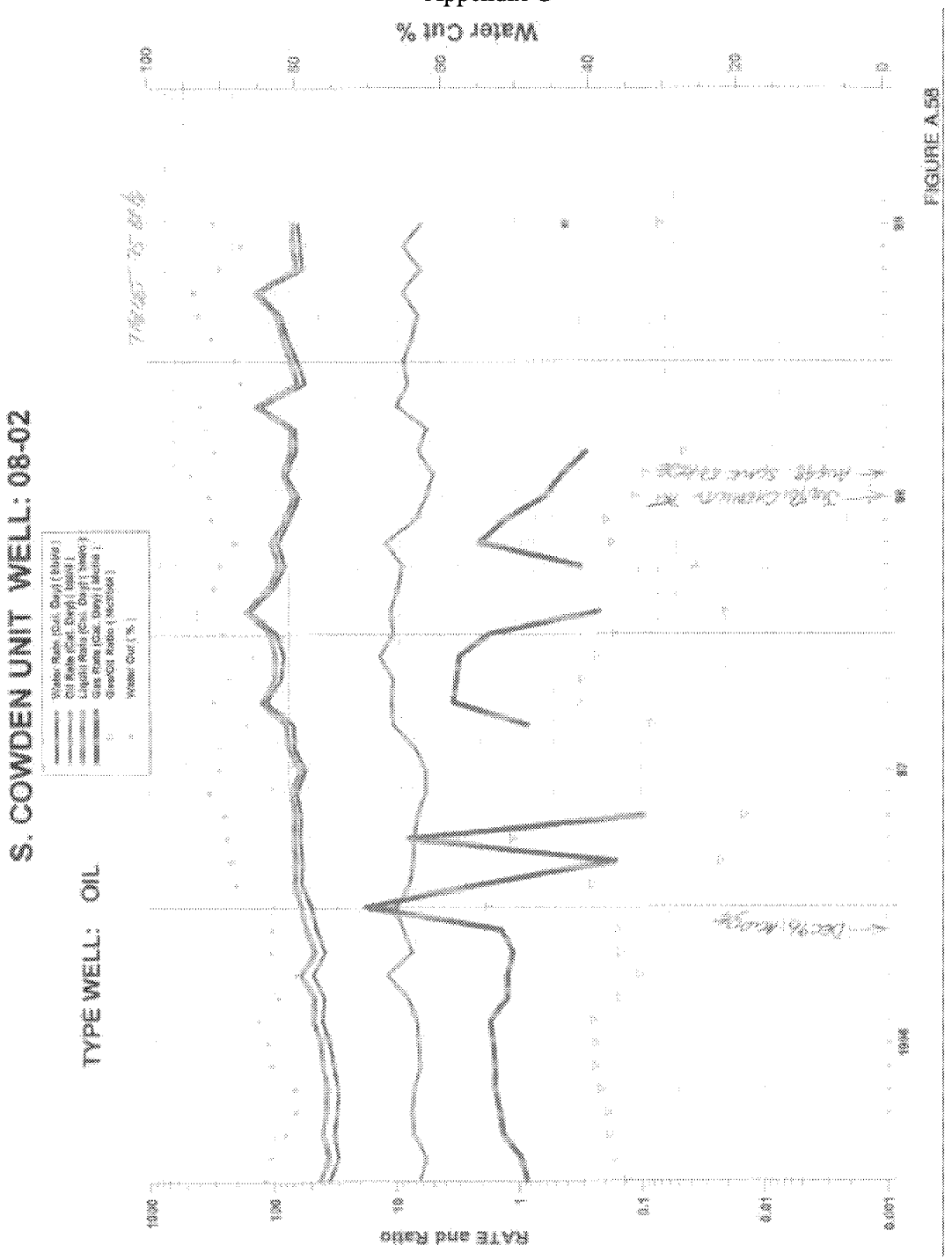
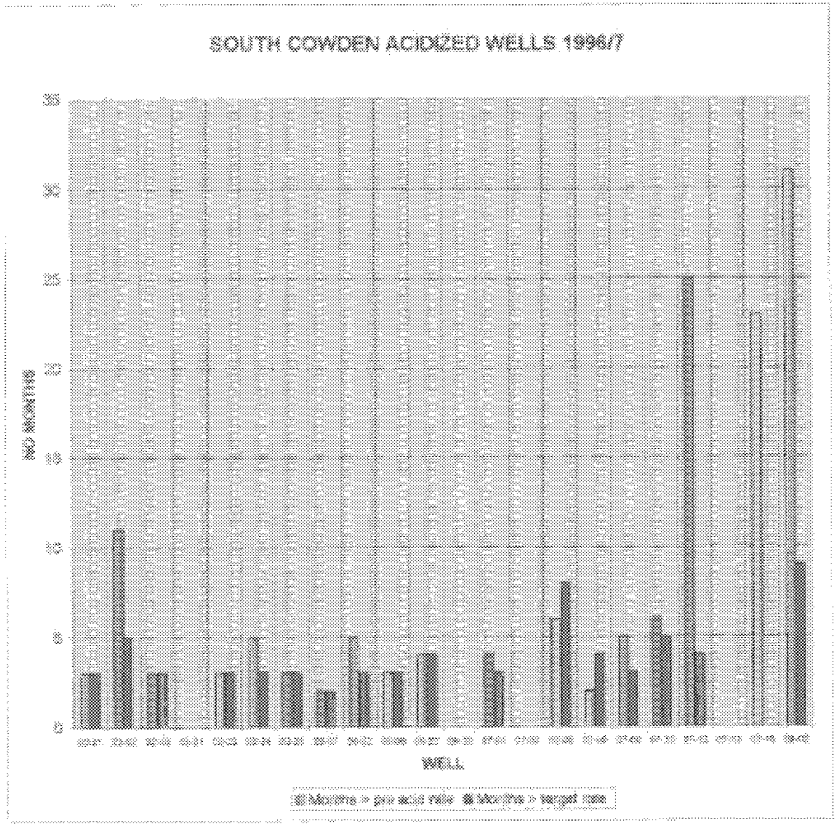

S. COWDEN UNIT WELL: 08-02
TYPE WELL: OIL
Water Cut %
RATE and Ratio

FIGURE A.58

SOUTH COWDEN ACID STIMULATION PERFORMANCE

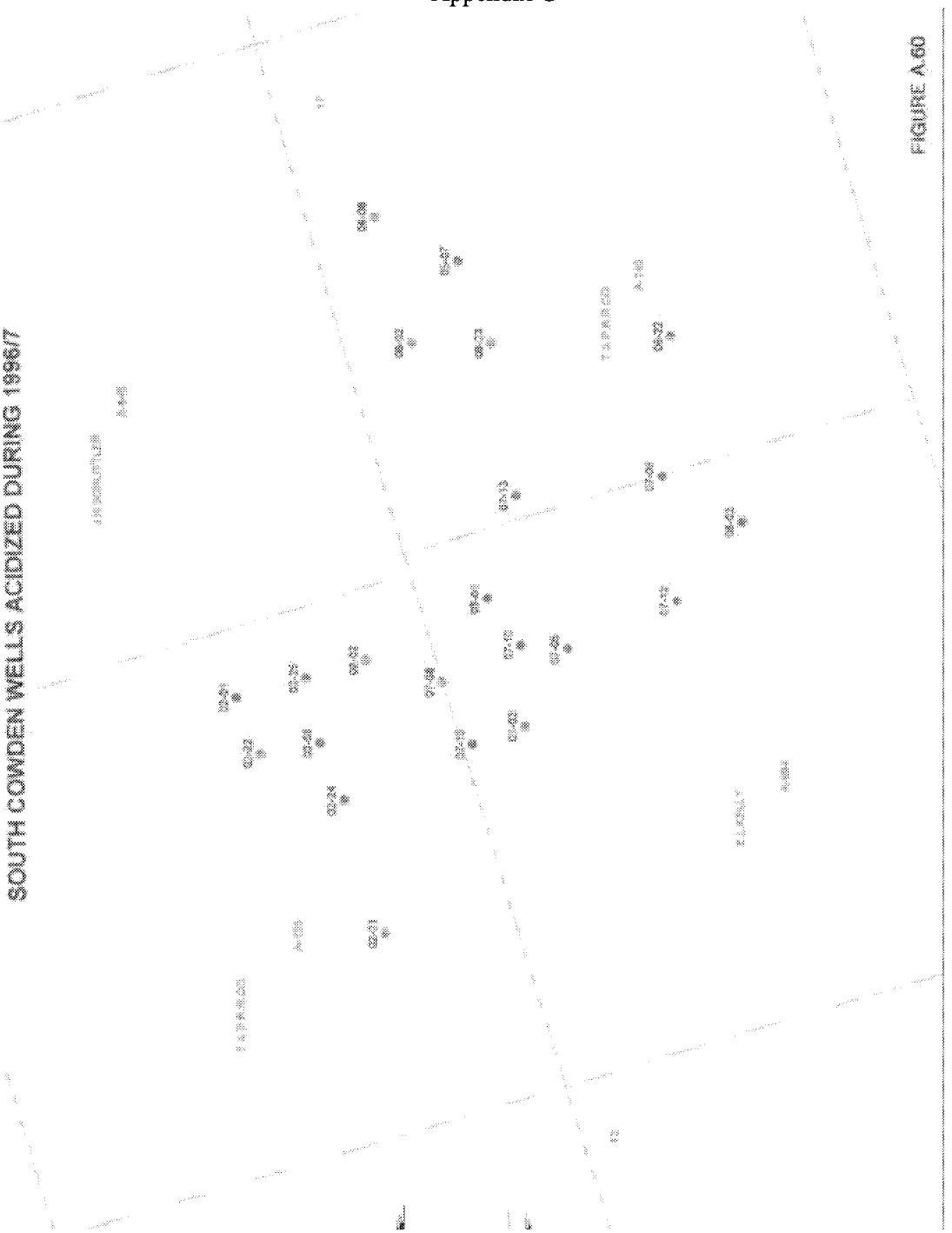


SOUTH COWDEN ACIDIZED WELLS 1996/7

WELL	No Months* > pre acid	No Months** >target	Comment
02-01	3	3	
02-02	11	5	
02-08	3	3	
02-21	n/a		Added perfs & Acidized
02-22	3	3	
02-24	5	3	
02-25	3	3	
05-07	2	2	
06-02	5	3	
06-06	3	3	
06-22	4	4	
06-23	n/a		Added perfs & Acidized
07-01	4	3	
07-02	0	0	
07-05	8	8	
07-08	2	4	
07-09	5	3	
07-10	8	5	
07-12	25	4	
07-13	0	0	
07-15	23	0	
08-02	31	9	
Average	7.2	3.4	

** -No months offtake rates sustained above pre-acid job rate*
*** -No months >target (expected) offtake rate*

FIGURE A.59


SOUTH COWDEN WELLS ACIDIZED DURING 1996/7
FIGURE A.60

624 HALIBURTON CORE ACID REACTION/SOLUBILITY TESTS

					TEST1			TEST2	
					Temp degF	Temp degF	Temp degF		
	Core Description	Depth	core poro %	core perm mD	96	116	136		
					% loss	% loss	% loss	%sol as CaCo3	%sol as Co3
G zone	Dolo, anhy, ool	4606	2	0.01	7.6	17.9	19.2	82	49.2
Upper E	Dolo, sl anhy, sl frac	4678	9.3	1.44	26.3	47.5	57	100	60
Lower E	Dolo, sl anhy, pp	4687	9.7	5.84	53.7	64	74.6	100	60
Between C&D	Sd, v dolo	4733	12.2	0.17	2.6	7.7	7.7	49.5	29.7
C zone	Dolo, sl anhy, vuggy, vert frac	4745	15.5	831.96	96	90.7	96.1	100	60

TEST 1: PERCENT WEIGHT LOSS WHEN EXPOSED to 15% HCL FOR 15 MINUTES
TEST2: ACID SOLUBILITY

FIGURE A.61

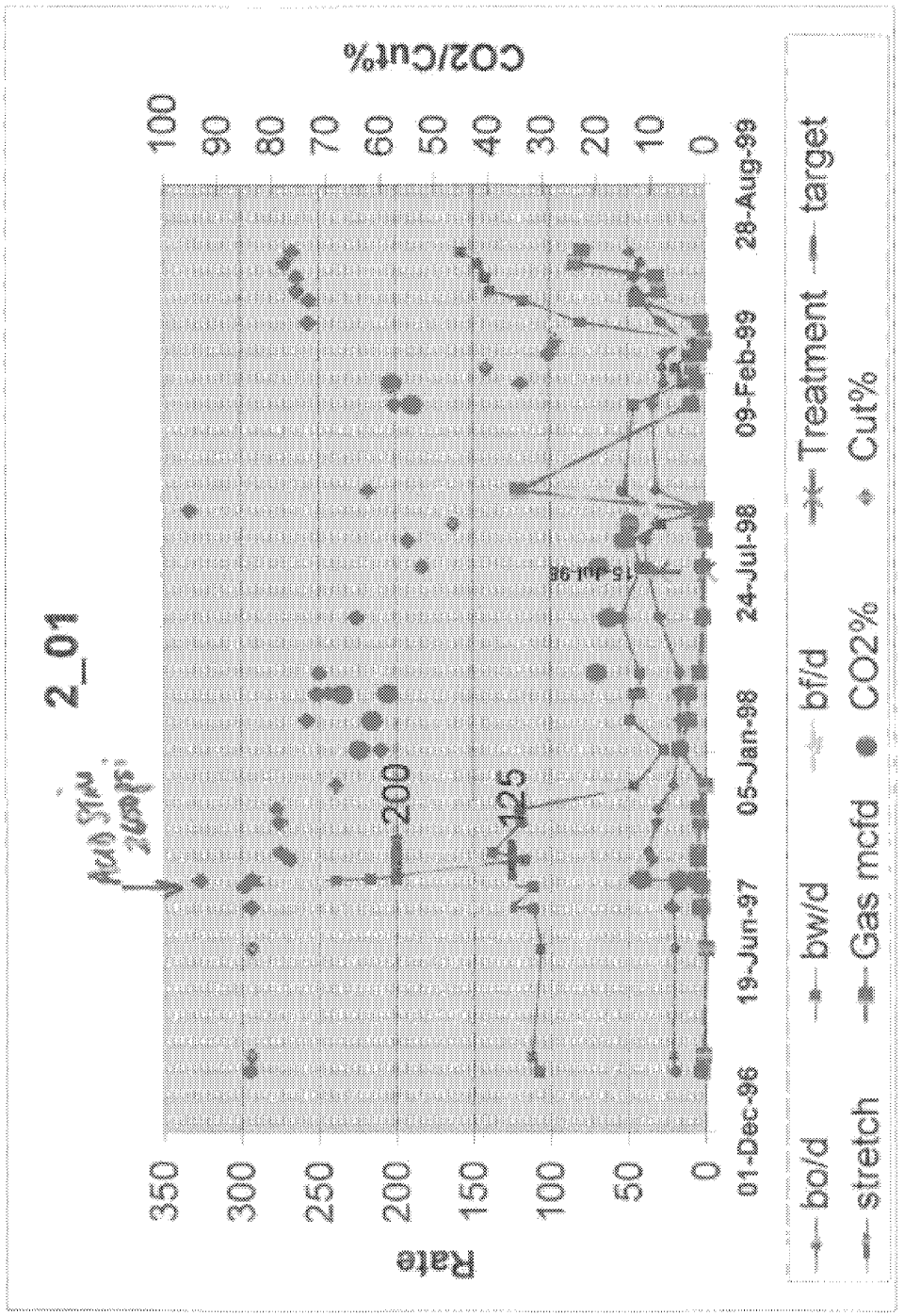

2_01
Rate
CO2/Cut%
100
90
80
70
60
50
40
30
20
10
0
350
300
250
200
150
100
50
0
01-Dec-96
19-Jun-97
05-Jan-98
24-Jul-98
09-Feb-99
28-Aug-99
200
125
bo/d
bw/d
bf/d
Treatment
target
stretch
Gas mcfd
CO2%
Cut%

FIGURE A.62

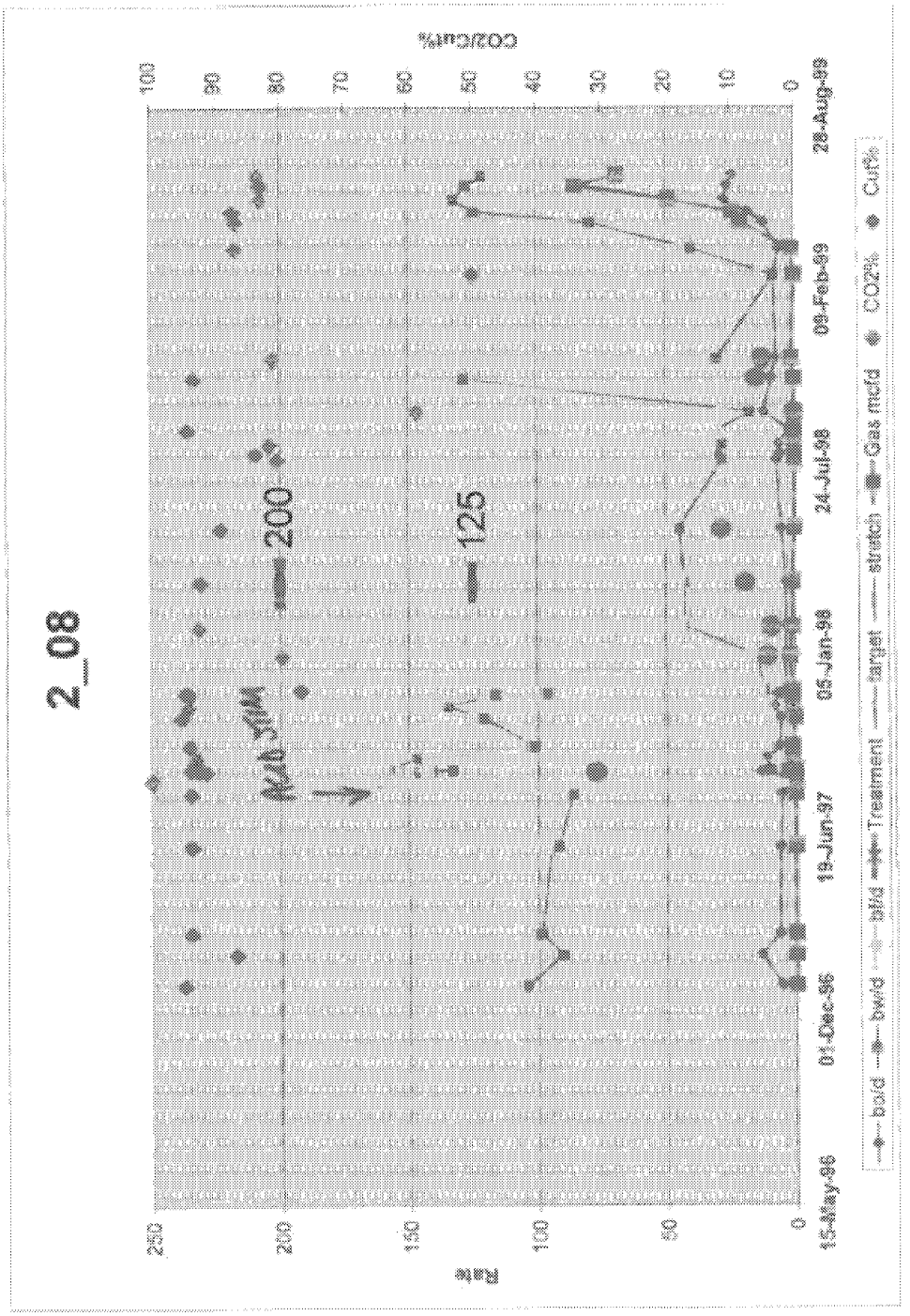

2_08
Rate
CO2/Cut%
15-May-96
01-Dec-96
19-Jun-97
05-Jan-98
24-Jul-98
09-Feb-99
28-Aug-99
200
125
bo/d
bw/d
bl/d
Treatment
target
stretch
Gas mcfd
CO2%
Cut%

FIGURE A.63

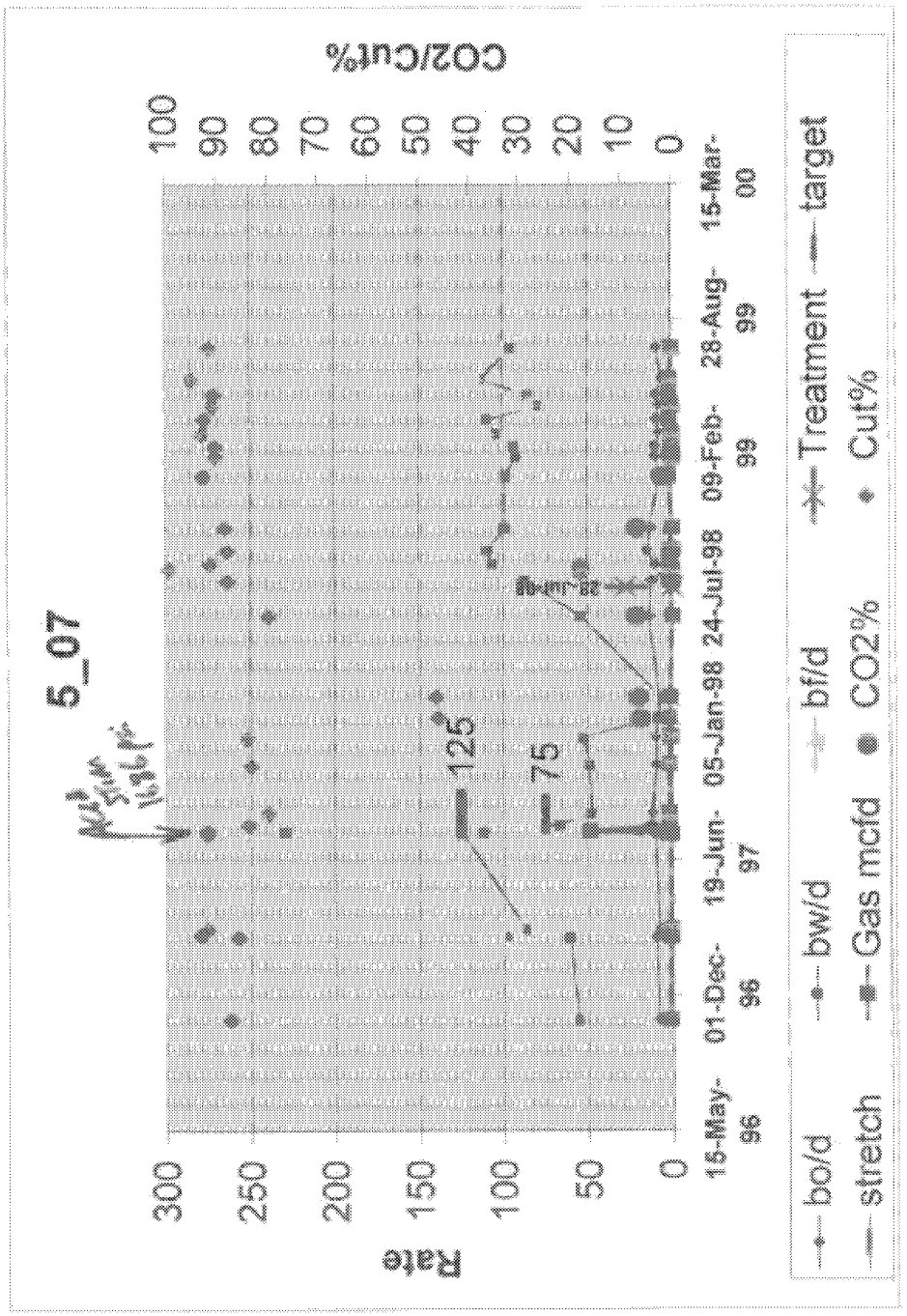

5_07
Rate
CO2/Cut%
300
250
200
150
100
50
0
100
90
80
70
60
50
40
30
20
10
0
125
75
15-May-96
01-Dec-96
19-Jun-97
05-Jan-98
24-Jul-98
09-Feb-99
28-Aug-99
15-Mar-00
bo/d
bw/d
bf/d
Treatment
target
stretch
Gas mcfd
CO2%
Cut%

FIGURE A.64

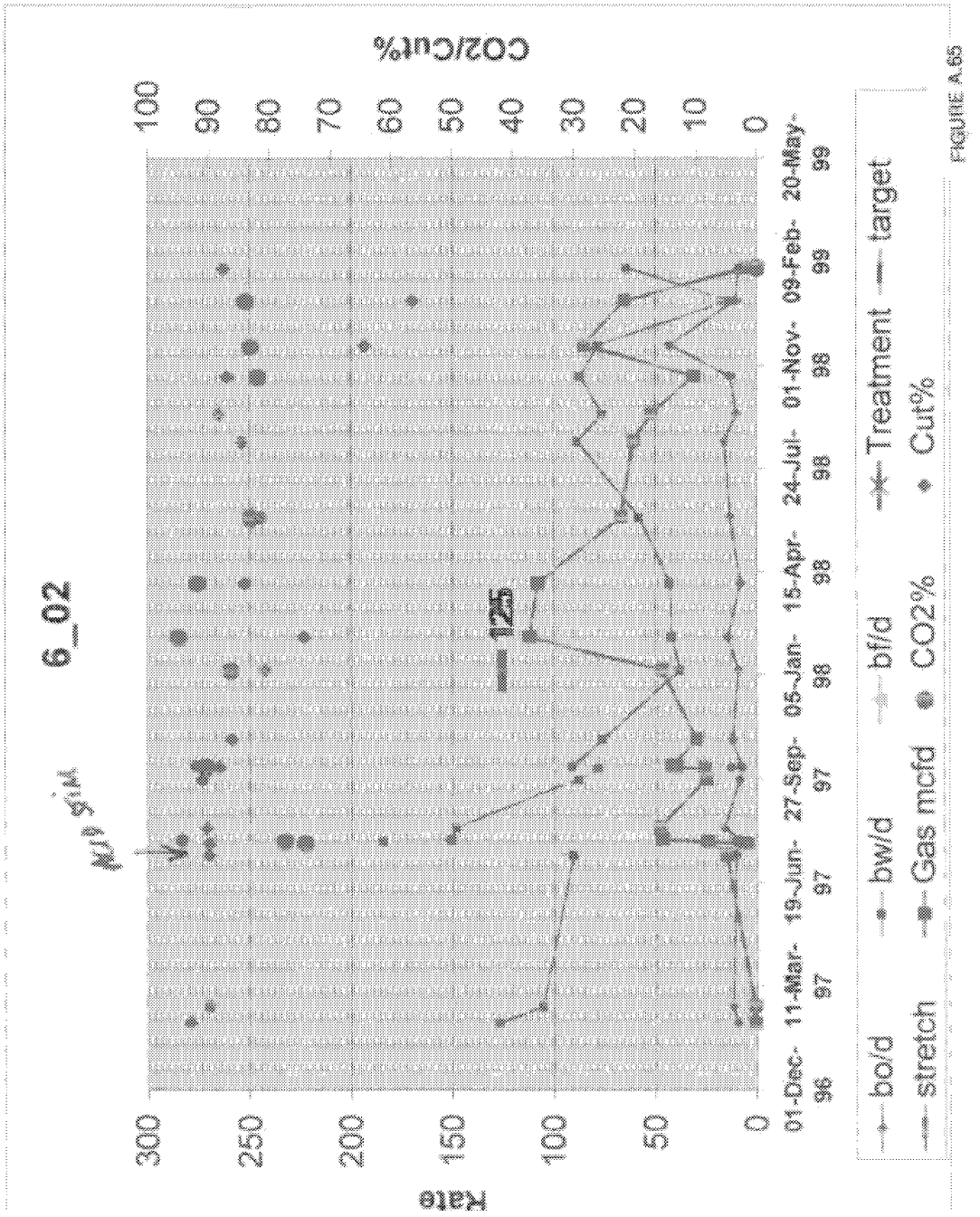

6_02
125
Rate
CO2/Cut%
300
250
200
150
100
50
0
100
90
80
70
60
50
40
30
20
10
0
01-Dec-96
11-Mar-97
19-Jun-97
27-Sep-97
05-Jan-98
15-Apr-98
24-Jul-98
01-Nov-98
09-Feb-99
20-May-99
bo/d
bw/d
bf/d
Treatment
target
stretch
Gas mcfd
CO2%
Cut%

FIGURE A.65

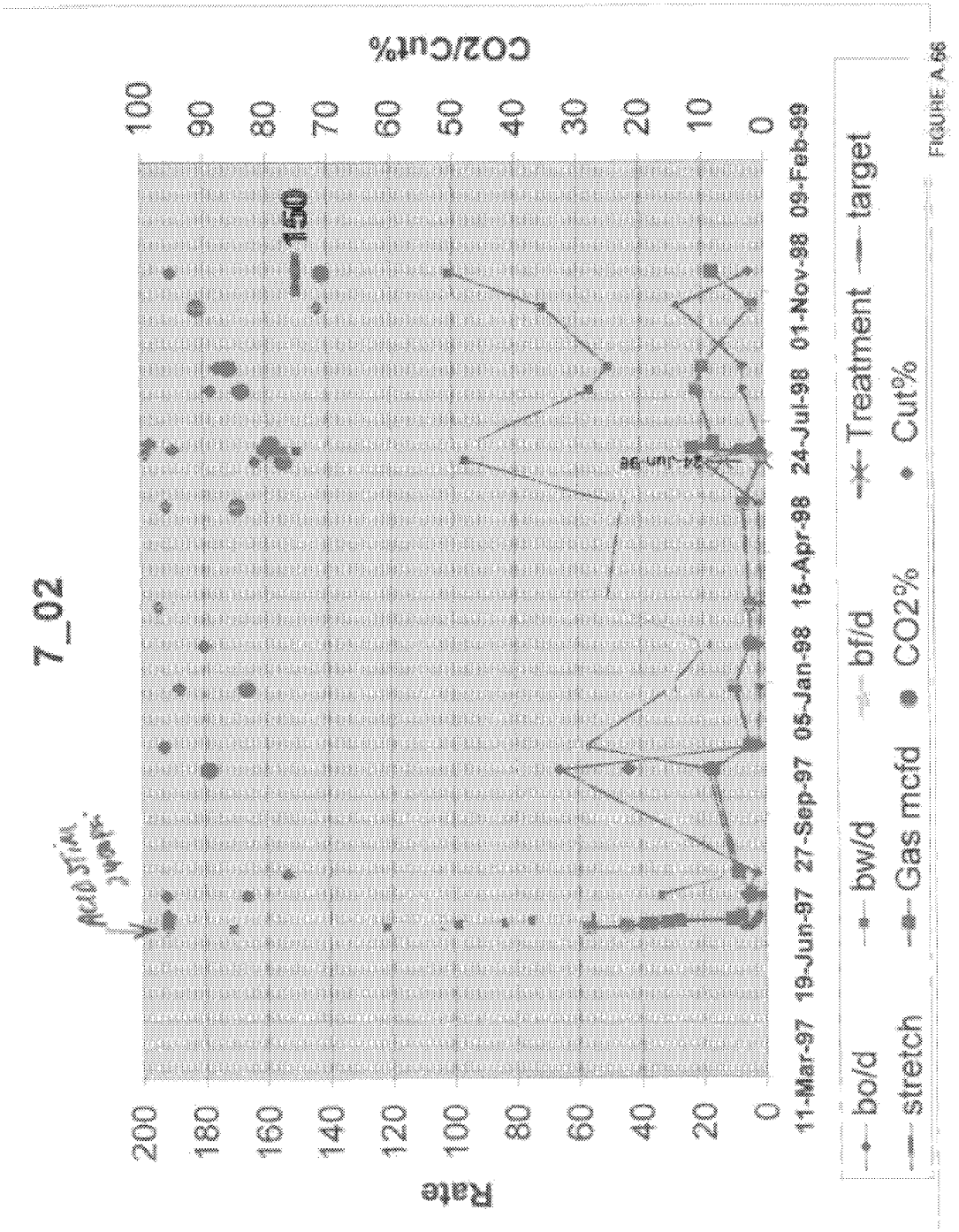

7_02
Rate
CO2/Cut%
150
11-Mar-97
19-Jun-97
27-Sep-97
05-Jan-98
15-Apr-98
24-Jul-98
01-Nov-98
09-Feb-99
bo/d
bw/d
bf/d
Treatment
target
stretch
Gas mcfd
CO2%
Cut%

FIGURE A-66

SOUTH COWDEN PRODUCTIVITY/INJECTIVITY IMPROVEMENT TECHNOLOGIES

	COST PER WELL	DEPTH PENETRATION	AVAILABILITY	RISK - UNPROVEN
STIMGUN	$15k	4 to 6 ft	NOW	NO
LANCE PERF	$7k	10 ft	NOW	MED
ACIDIZATION	$25k	n/a	NOW	NO
JETTING - HOSE	$75k	200 to 300 ft	NO - requires development	HIGH
JETTING- COIL	unknown	200 to 300 ft	NO - requires development	HIGH
SHORT RADIUS LATERAL	$100k	750 ft	NOW	NO
SHORT RADIUS 2 LATERALS	$155k	750 ft	NOW	NO
SHORT RADIUS 3 LATERALS	$225k	750 ft	NOW	NO

2/22/00

NEW_REENTERED AFE VS ACTUAL

FIGURE A.67

Appendix G

STIMGUN PERFORATING

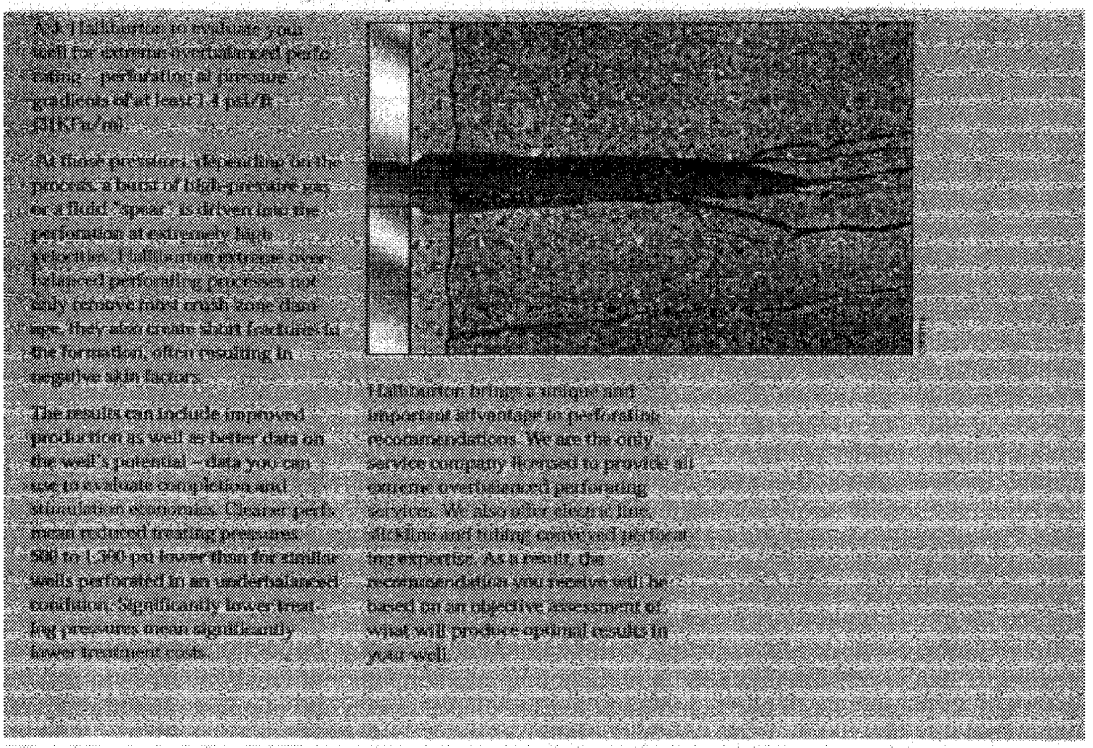


FIGURE A.60

Appendix G

LANCED PERFORATING TECHNIQUE

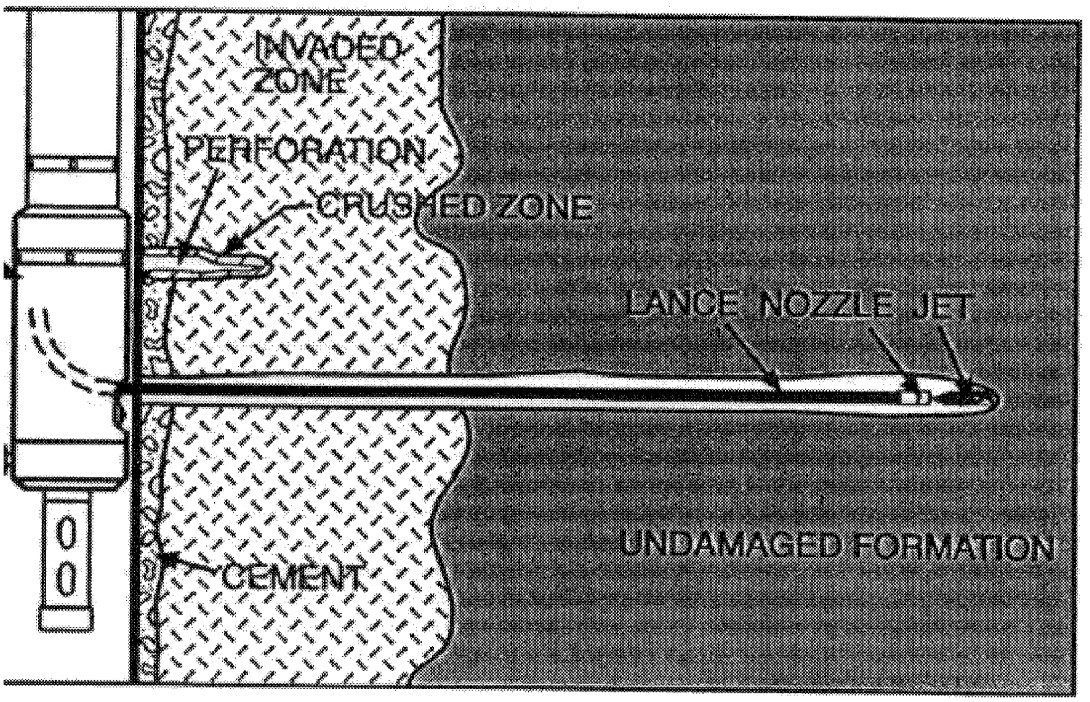


FIGURE A.69

Appendix G

LATERAL JETTING TECHNIQUE

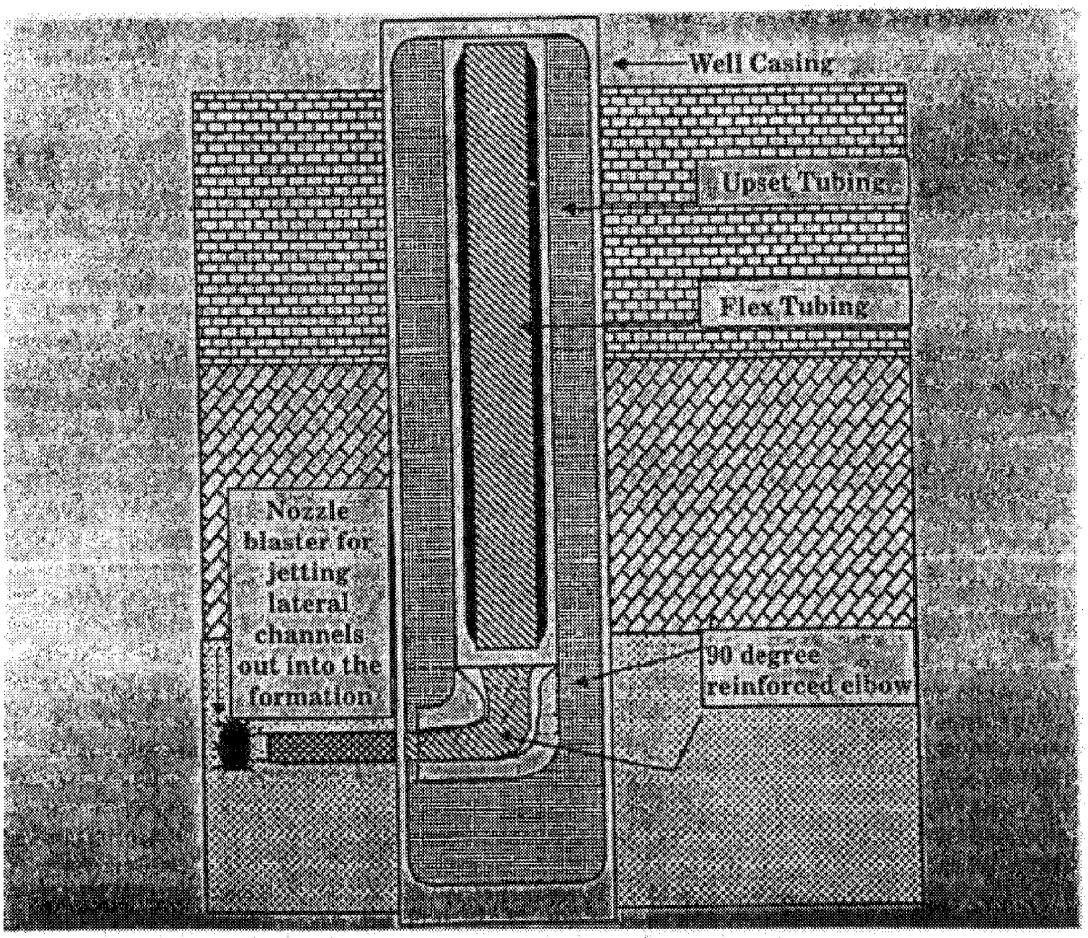


FIGURE A.70

PHILLIPS PETROLEUM
Wellbore Preparation Schematic
South Cowden Unit - #602

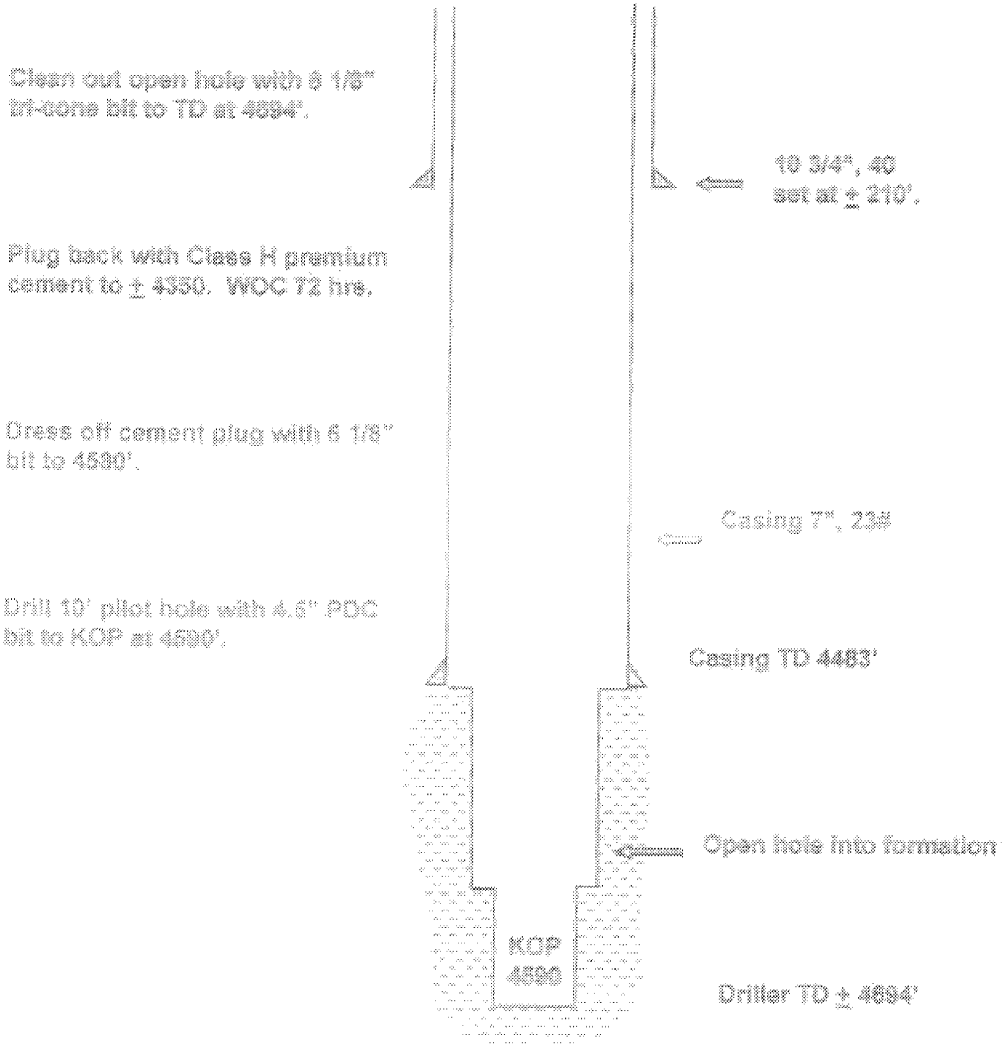


FIGURE A.71

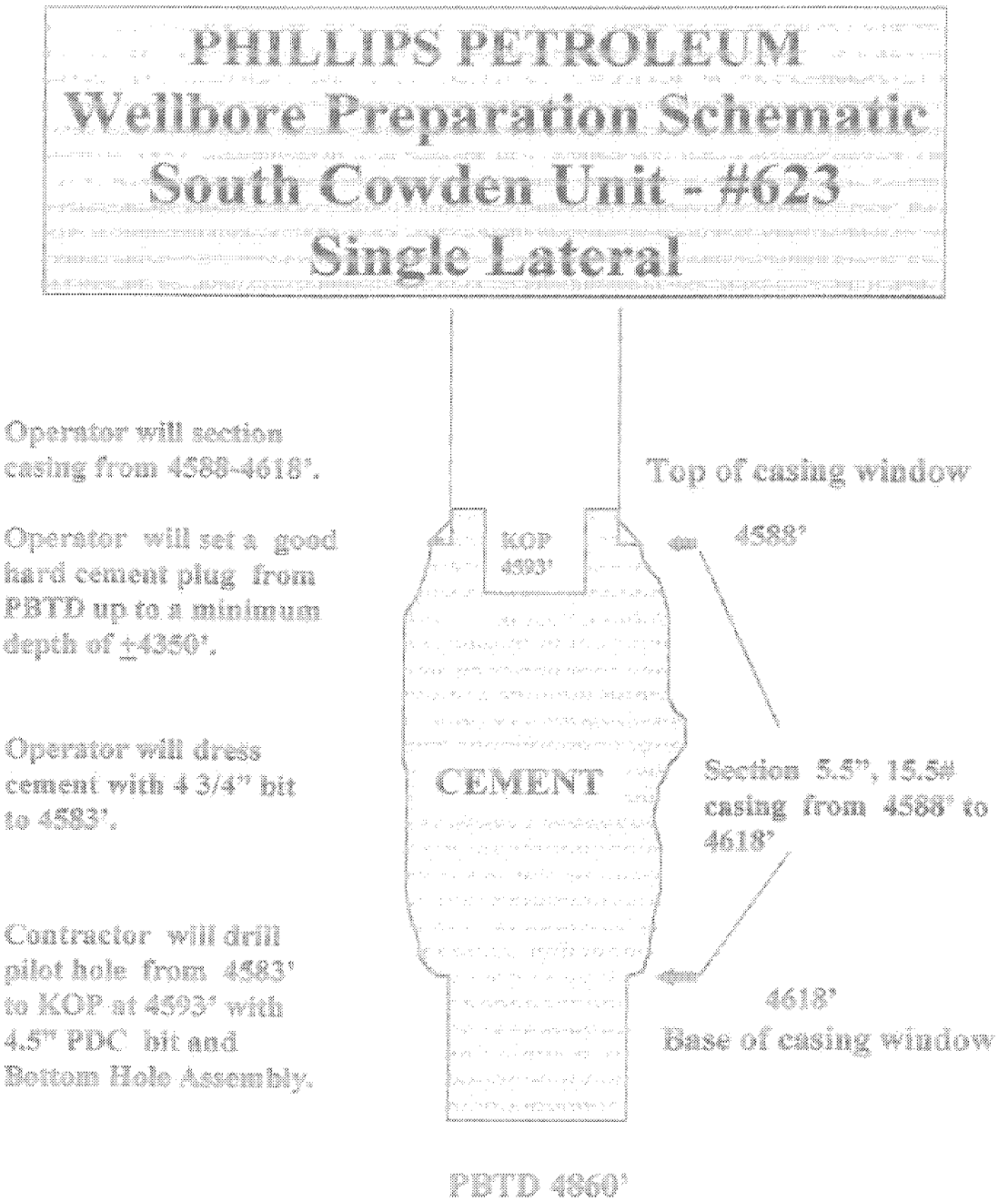

PHILLIPS PETROLEUM
Wellbore Preparation Schematic
South Cowden Unit - #623
Single Lateral
Operator will section casing from 4588-4618'.
Operator will set a good hard cement plug from PBTD up to a minimum depth of ±4350'.
Operator will dress cement with 4 3/4" bit to 4583'.
Contractor will drill pilot hole from 4583' to KOP at 4593' with 4.5" PDC bit and Bottom Hole Assembly.
Top of casing window
4588'
KOP
4593'
CEMENT
Section 5.5", 15.5# casing from 4588' to 4618'
4618'
Base of casing window
PBTD 4860'

FIGURE A.72

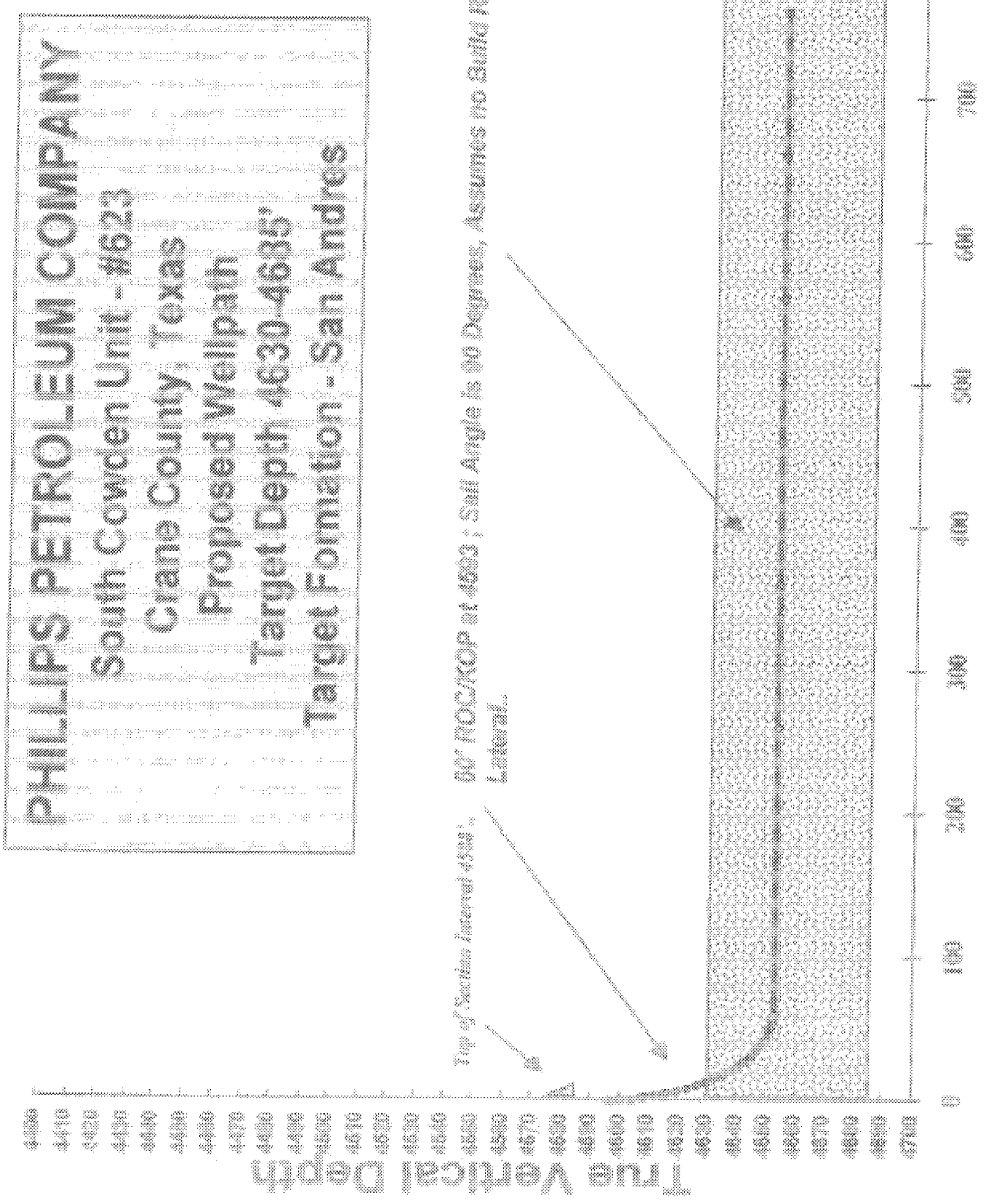

PHILLIPS PETROLEUM COMPANY
South Cowden Unit - #623
Crane County, Texas
Proposed Wellpath
Target Depth 4630-4635'
Target Formation - San Andres
Top of Section Interval 4584'
80' ROC/KOP at 4563' ; Salt Angle is 90 Degrees, Assumes no Build Rate in Lateral.
True Vertical Depth
Total Departure

FIGURE A.73

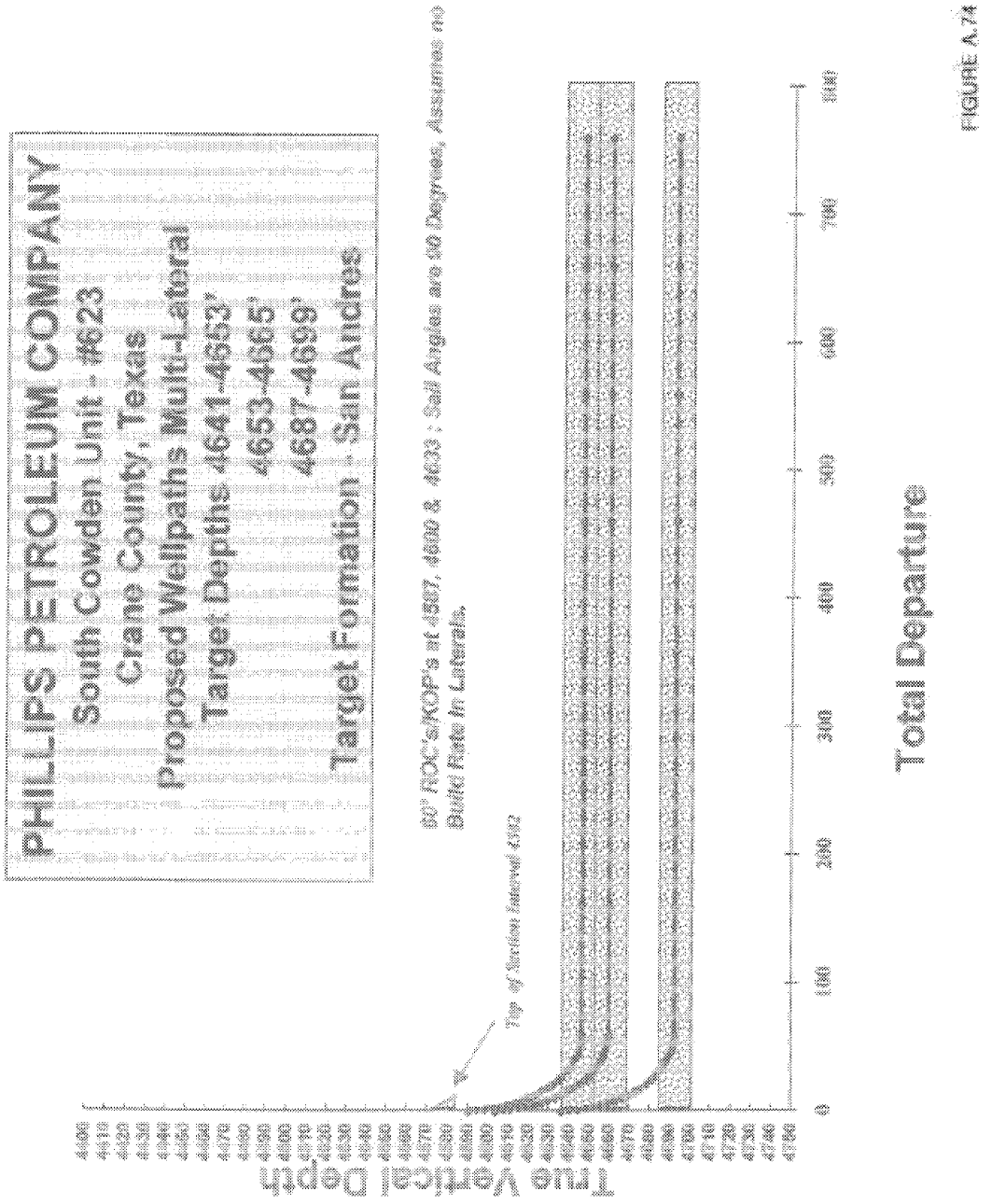
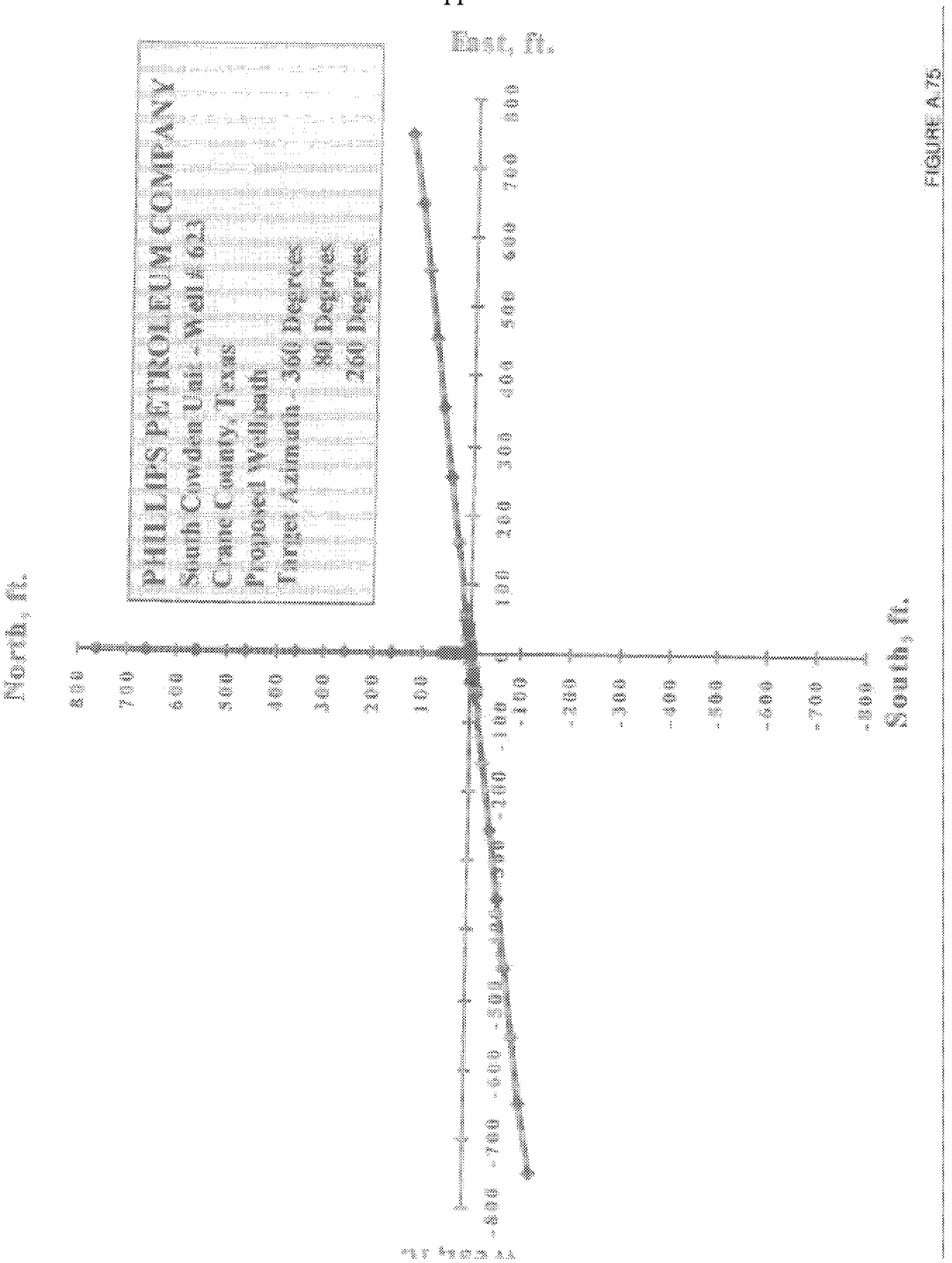

PHILLIPS PETROLEUM COMPANY
South Cowden Unit - #623
Crane County, Texas
Proposed Wellpaths Multi-Lateral
Target Depths 4641-4653'
4653-4665'
4687-4699'
Target Formation - San Andres
60° ROC's/KOP's at 4597, 4630 & 4633 ; Salt Angles are 90 Degrees, Assumes no Build Rate In Laterals.
Top of Service Interval 4582
True Vertical Depth
Total Departure
0
100
200
300
400
500
600
700
800

FIGURE A.74

Appendix G


PHILLIPS PETROLEUM COMPANY
South Cowden Unit - Well #23
Crane County, Texas
Proposed Wellpath
Target Azimuth - 360 Degrees
80 Degrees
20 Degrees
East, ft.
North, ft.
South, ft.
FIGURE A-75

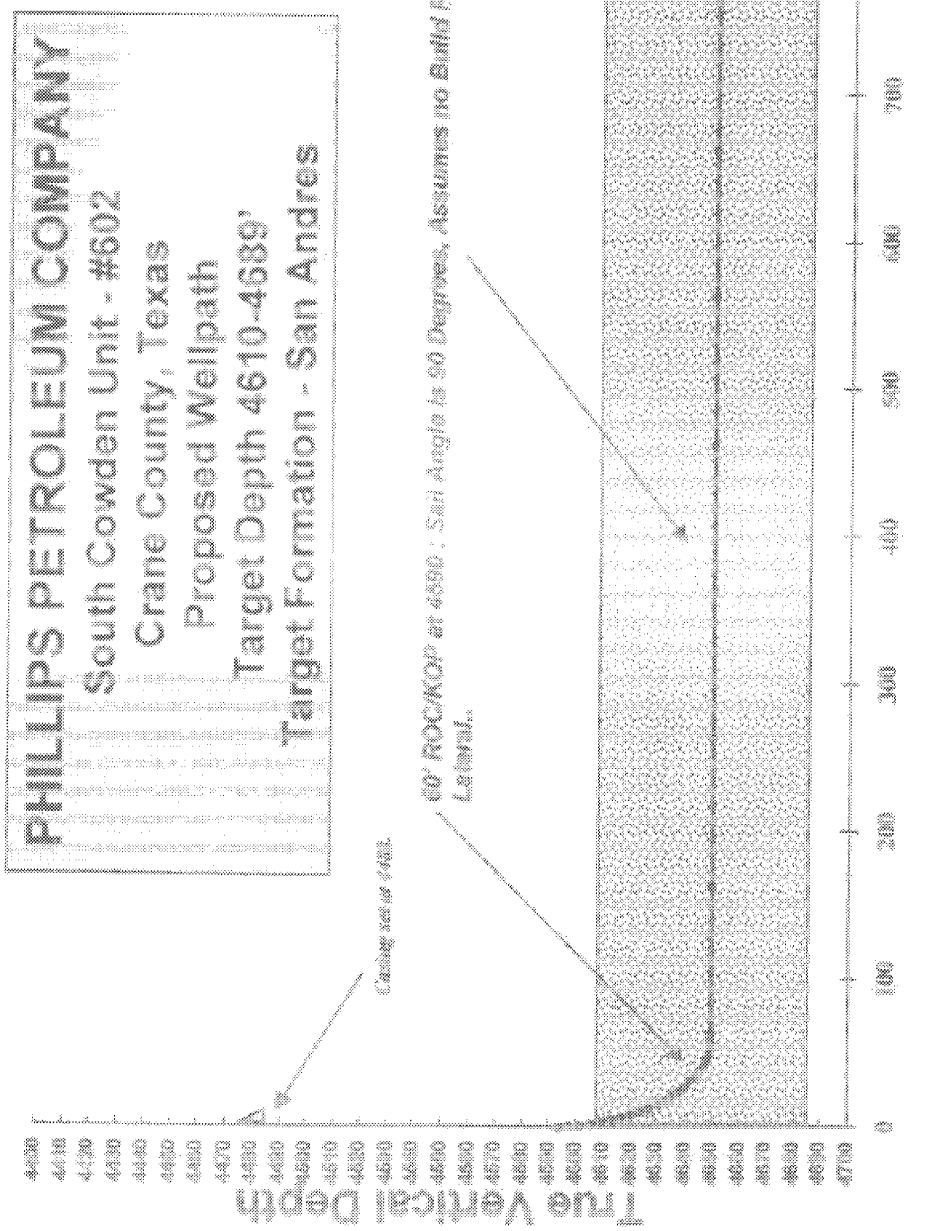

PHILLIPS PETROLEUM COMPANY
South Cowden Unit - #602
Crane County, Texas
Proposed Wellpath
Target Depth 4610-4639'
Target Formation - San Andres
60' ROC/KOP at 4390' ; Set Angle to 90 Degrees, Assume no Build Rate in Lateral.
True Vertical Depth
Total Departure

FIGURE A.76

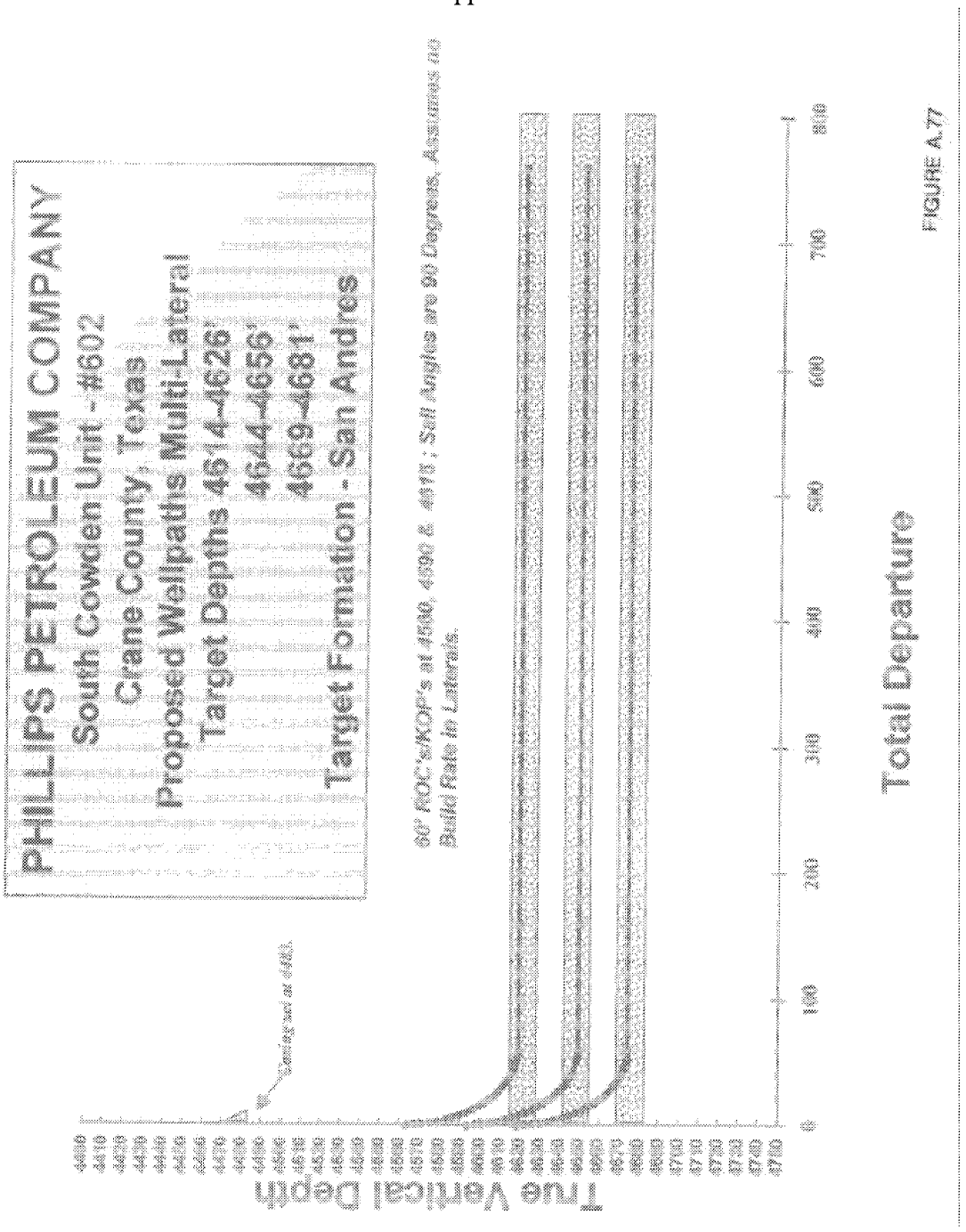
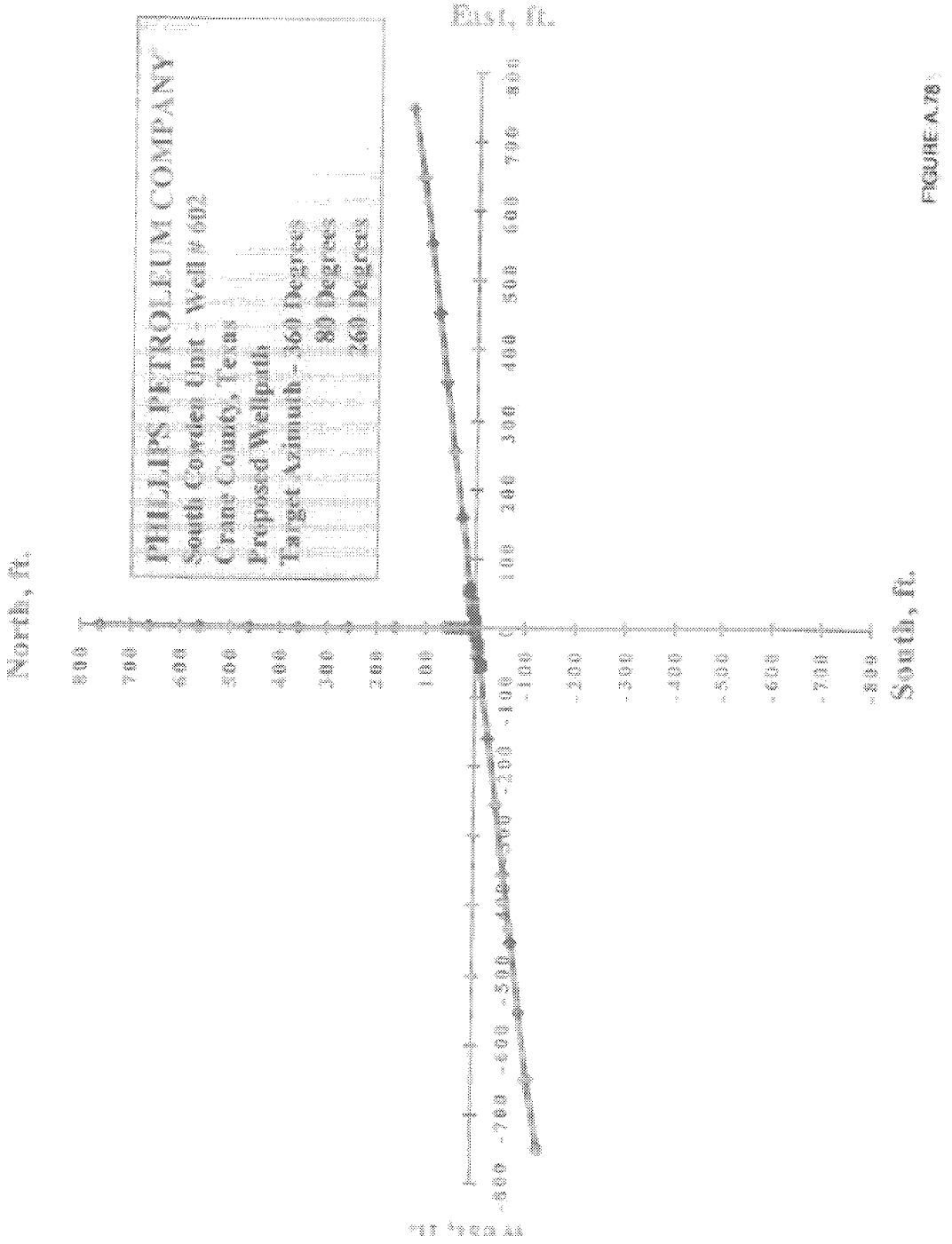

PHILLIPS PETROLEUM COMPANY
South Cowden Unit - #602
Crane County, Texas
Proposed Wellpaths Multi-Lateral
Target Depths 4614-4626'
4644-4656'
4669-4681'
Target Formation - San Andres
60' ROC's/KOP's at 4590, 4990 & 4910 ; Salt Angles are 90 Degrees, Azimuths no
Build Rate in Laterals.
Total Departure
True Vertical Depth

FIGURE A.77

Appendix G


PHILLIPS PETROLEUM COMPANY
South Cowden Unit - Well # 602
Crane County, Texas
Proposed Wellpath
Target Azimuth - 360 Degrees
80 Degrees
20 Degrees
East, ft.
North, ft.
South, ft.
FIGURE A-7B

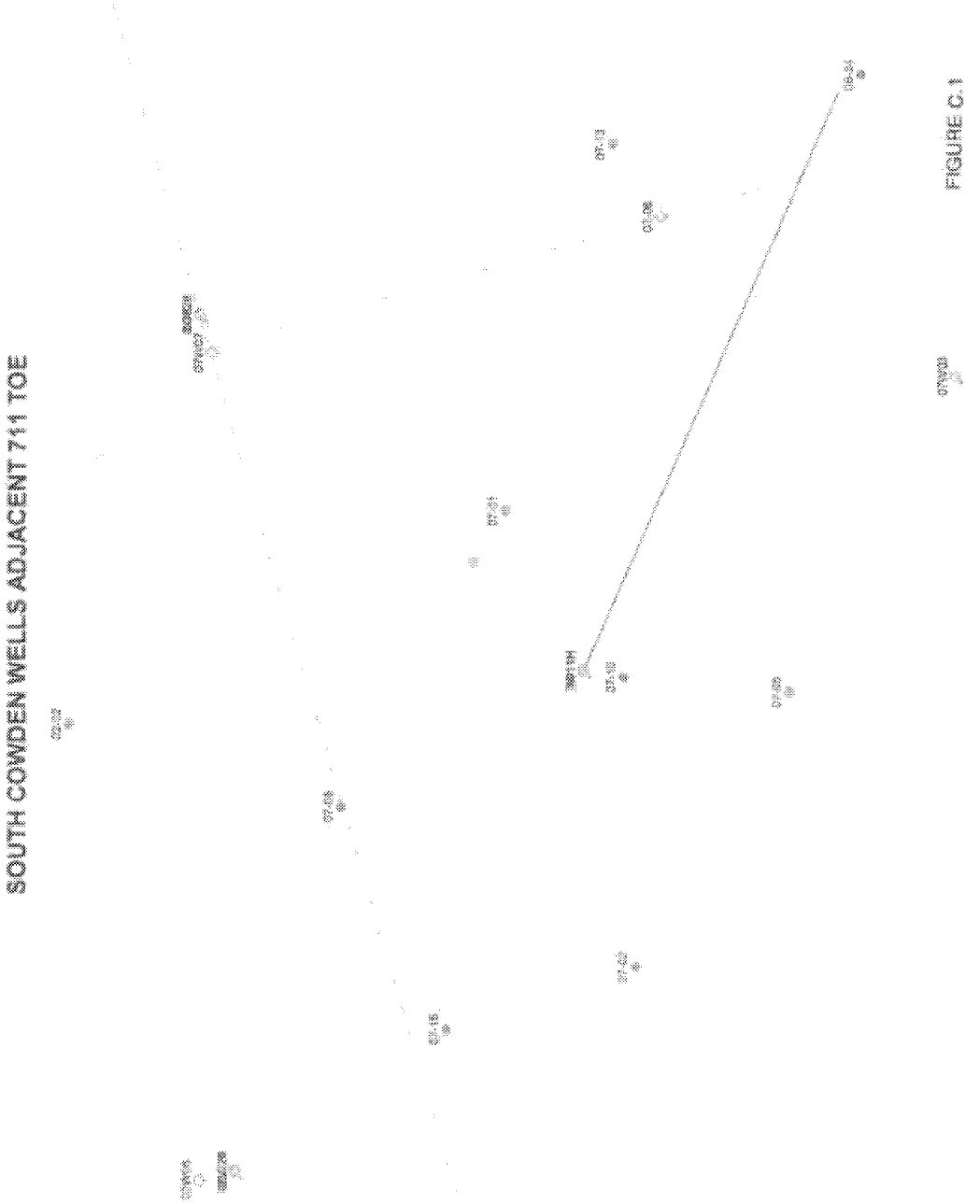
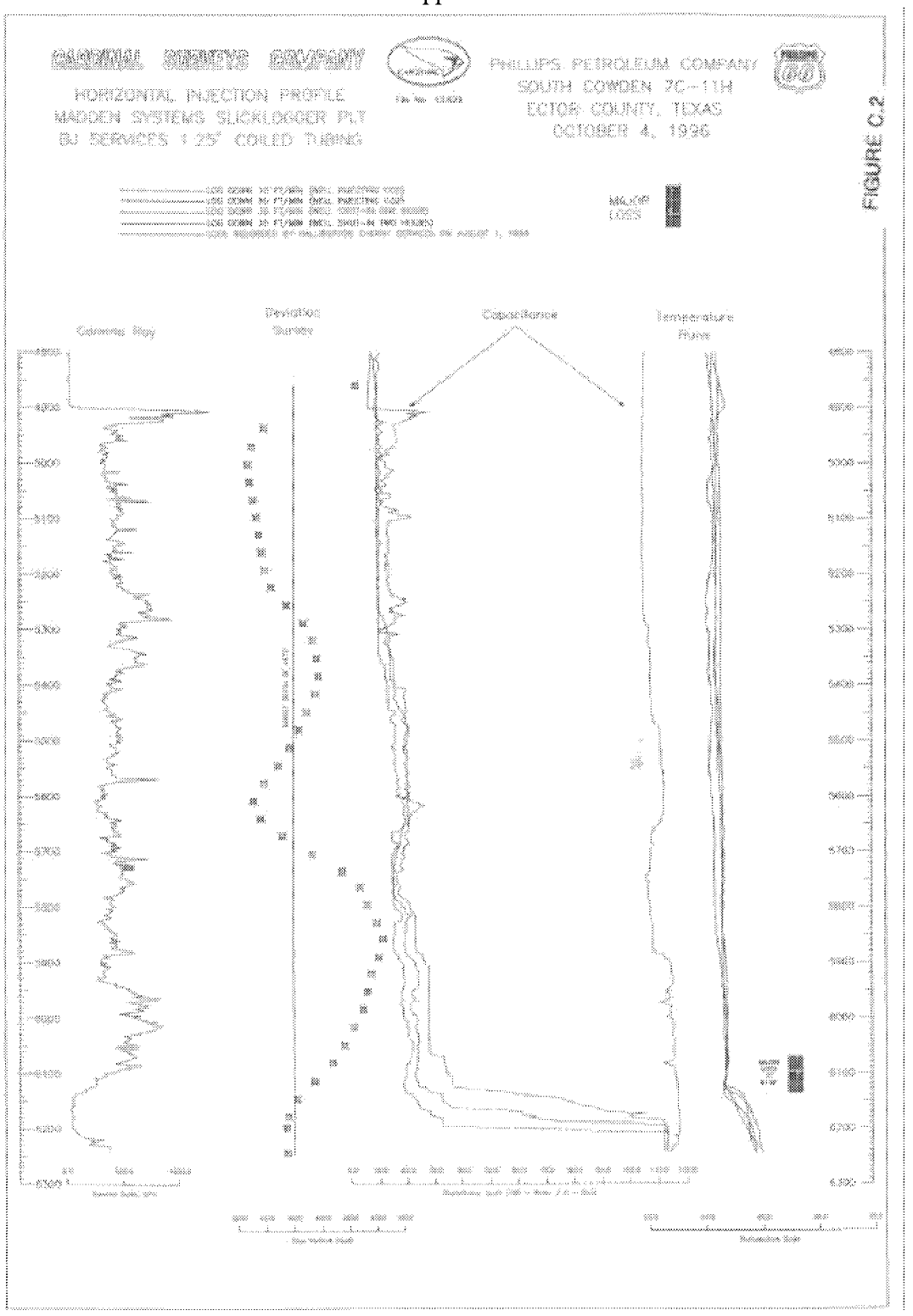


FIGURE C-1

Appendix G


HORIZONTAL INJECTION PROFILE
MADDEN SYSTEMS SLICKLOGGER PLT
BJ SERVICES 1.25" COILED TUBING
PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN 7C-11H
ECTOR COUNTY, TEXAS
OCTOBER 4, 1996
Gamma Ray
Deviation Survey
Capacitance
Temperature Flow
FIGURE C.2

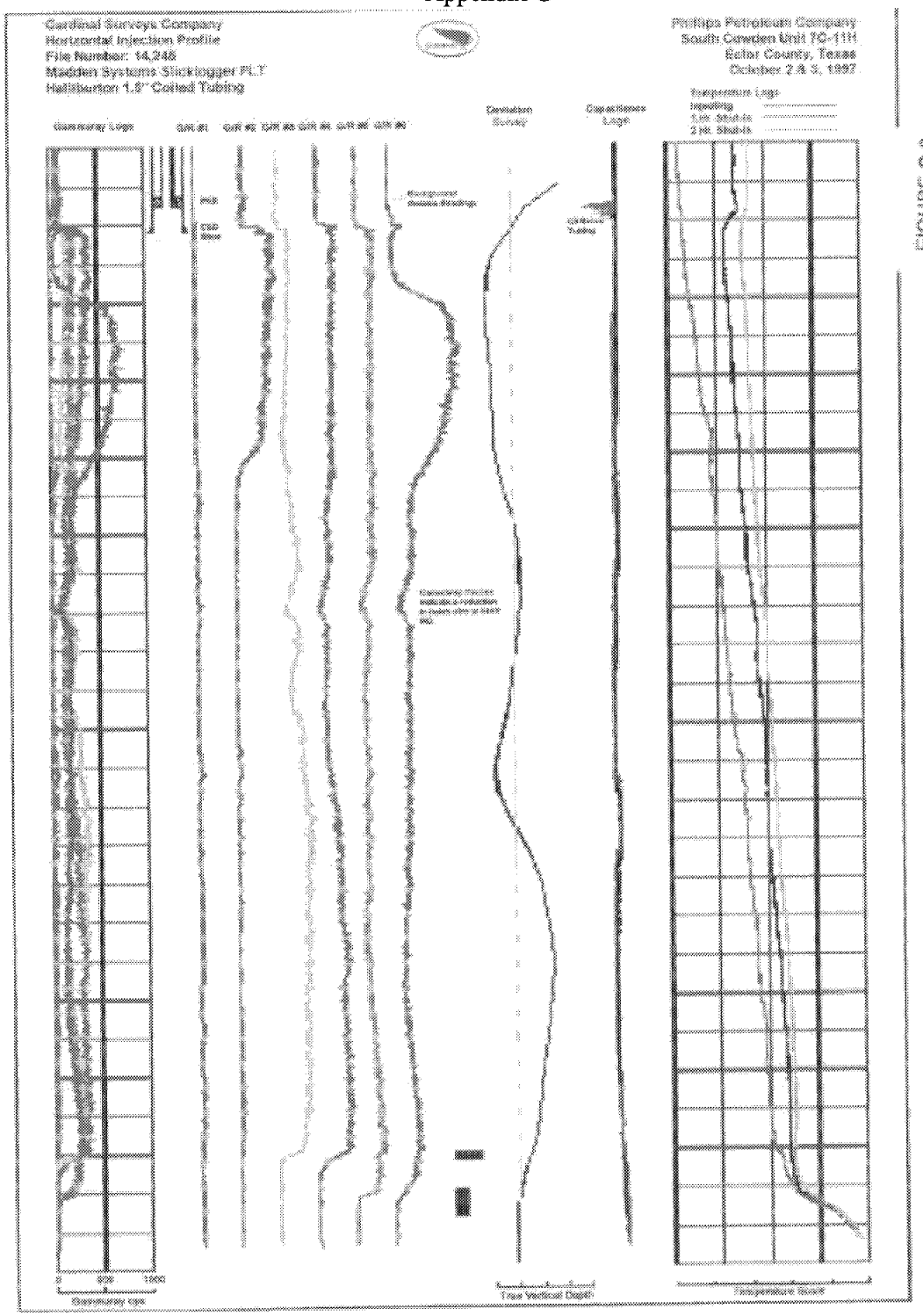

Cardinal Surveys Company
Horizontal Injection Profile
File Number: 14,248
Madden Systems Slickogger PLT
Halliburton 1.5" Coiled Tubing
Phillips Petroleum Company
South Cowden Unit 70-11H
Ector County, Texas
October 2 & 3, 1997
Gamma Ray Log
Deviation Survey
Cased Hole Log
Temperature Log
Injecting
1 Hr. Shut-In
2 Hr. Shut-In
Gamma Ray Log
True Vertical Depth
Temperature Scale

FIGURE C-3

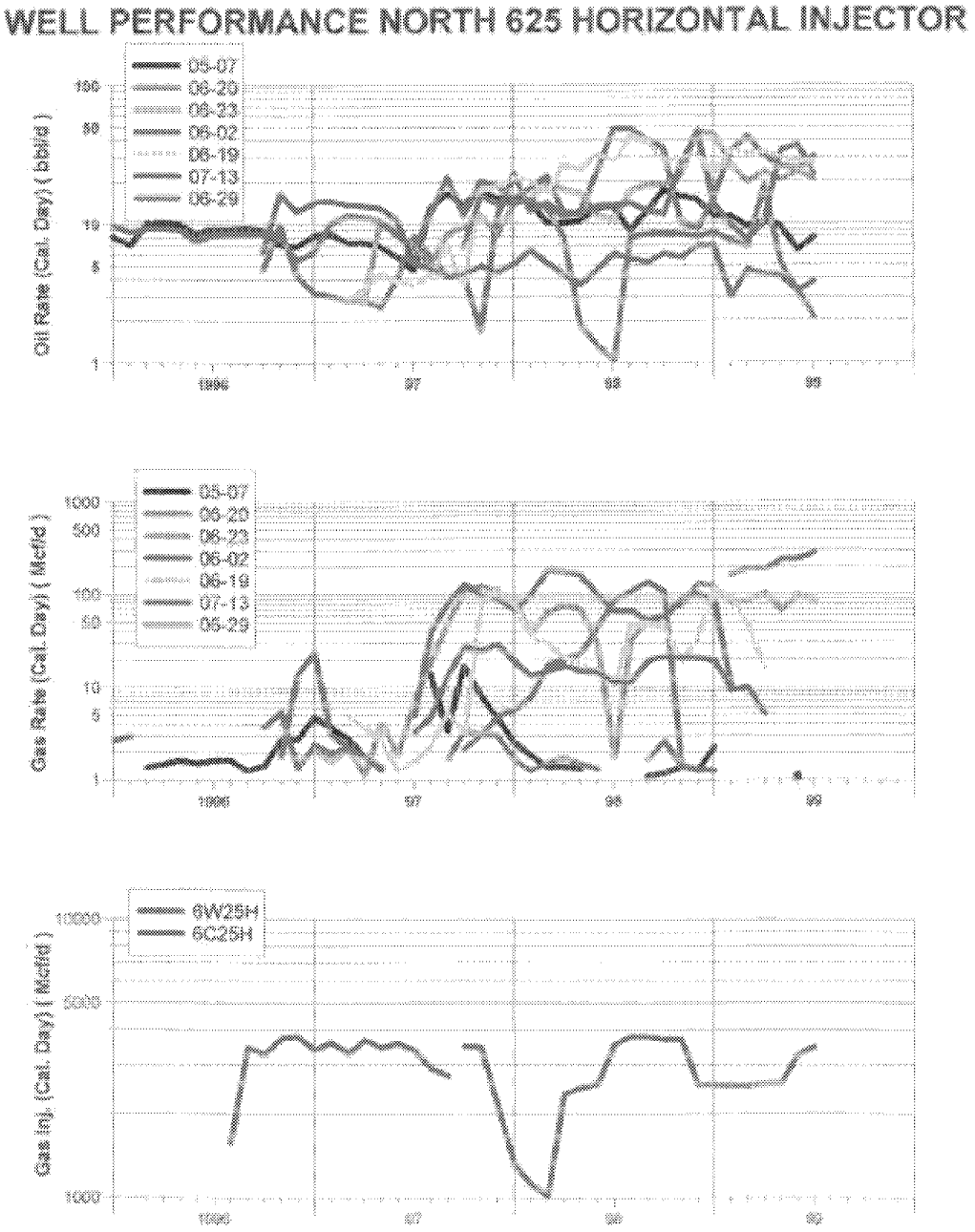

WELL PERFORMANCE NORTH 625 HORIZONTAL INJECTOR
05-07
06-20
06-23
06-02
06-19
07-13
05-29
Oil Rate (Cal. Day) (bbl/d)
100
50
10
5
1
1996
97
98
99
05-07
06-20
06-23
06-02
06-19
07-13
05-29
Gas Rate (Cal. Day) (Mcf/d)
1000
500
100
50
10
5
1
1996
97
98
99
9W25H
6C25H
Gas Inj. (Cal. Day) (Mcf/d)
10000
5000
1000
1996
97
98
99

FIGURE E-2

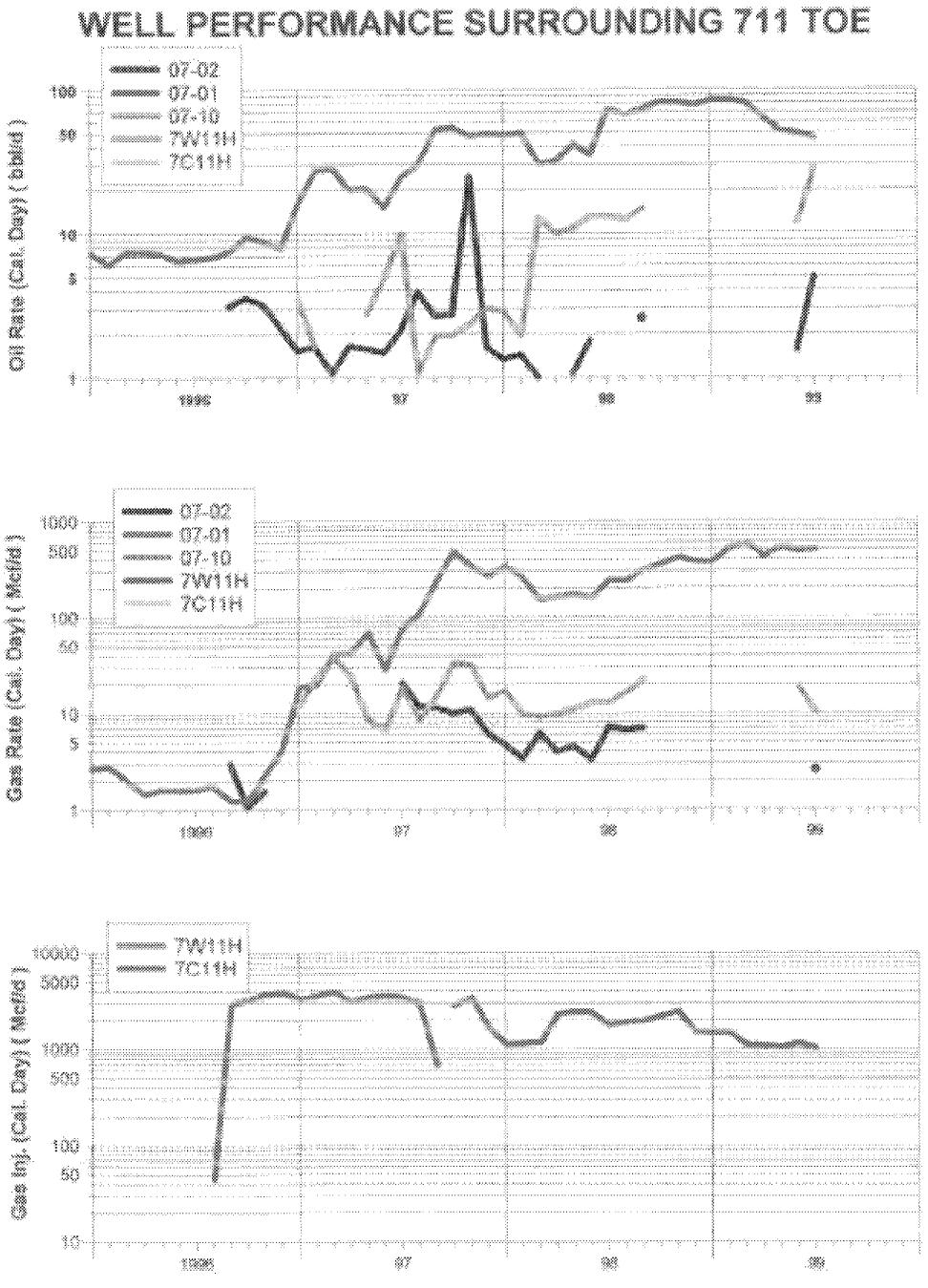

WELL PERFORMANCE SURROUNDING 711 TOE
07-02
07-01
07-10
7W11H
7C11H
Oil Rate (Cal. Day) (bbl/d)
Gas Rate (Cal. Day) (Mcf/d)
Gas Inj. (Cal. Day) (Mcf/d)
1996
97
98
99

FIGURE C.5

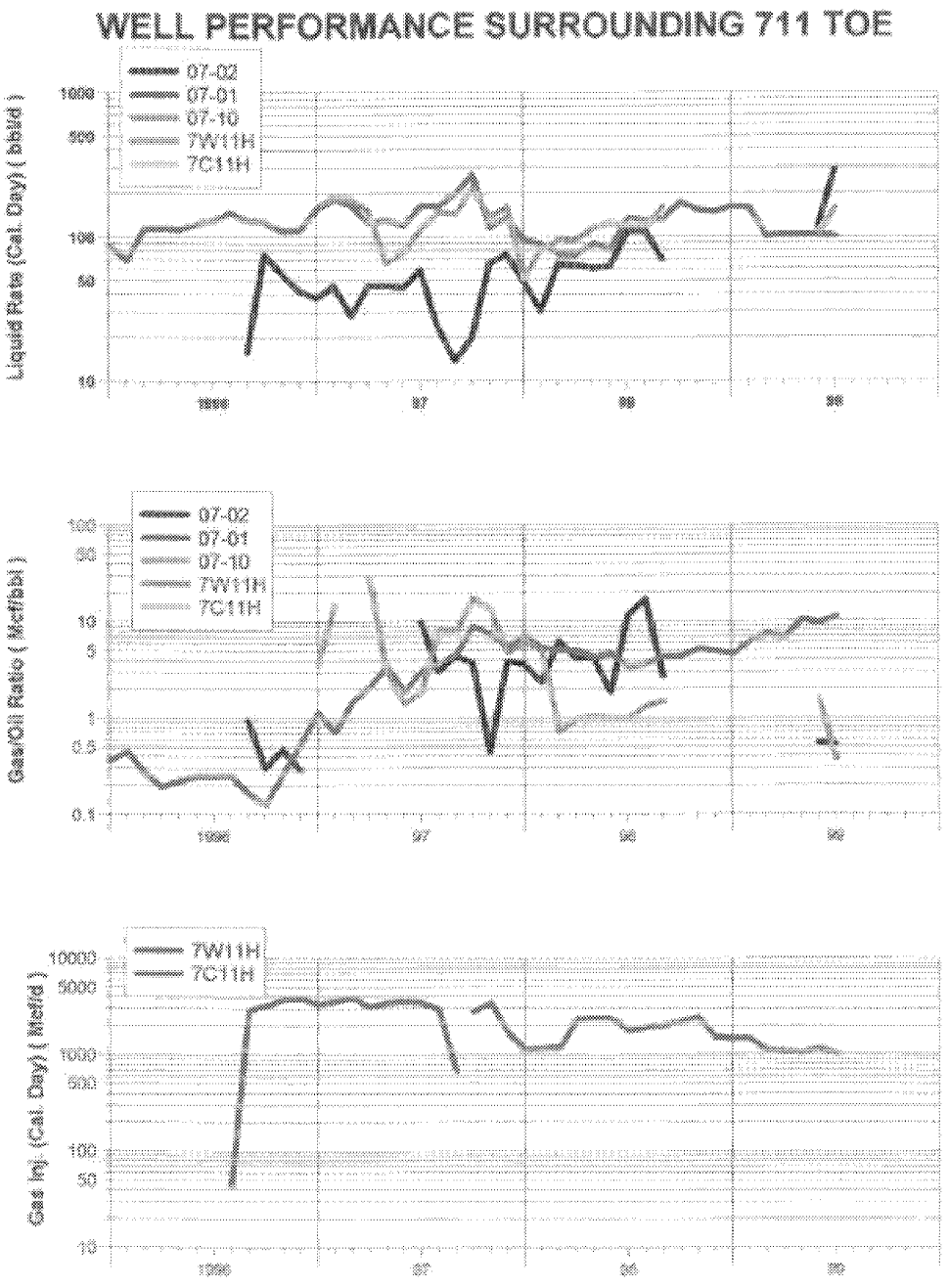

WELL PERFORMANCE SURROUNDING 711 TOE
07-02
07-01
07-10
7W11H
7C11H
Liquid Rate (Cal. Day) (bbl/d)
Gas/Oil Ratio (Mcf/bbl)
Gas Inj (Cal. Day) (Mcf/d)

FIGURE C.6

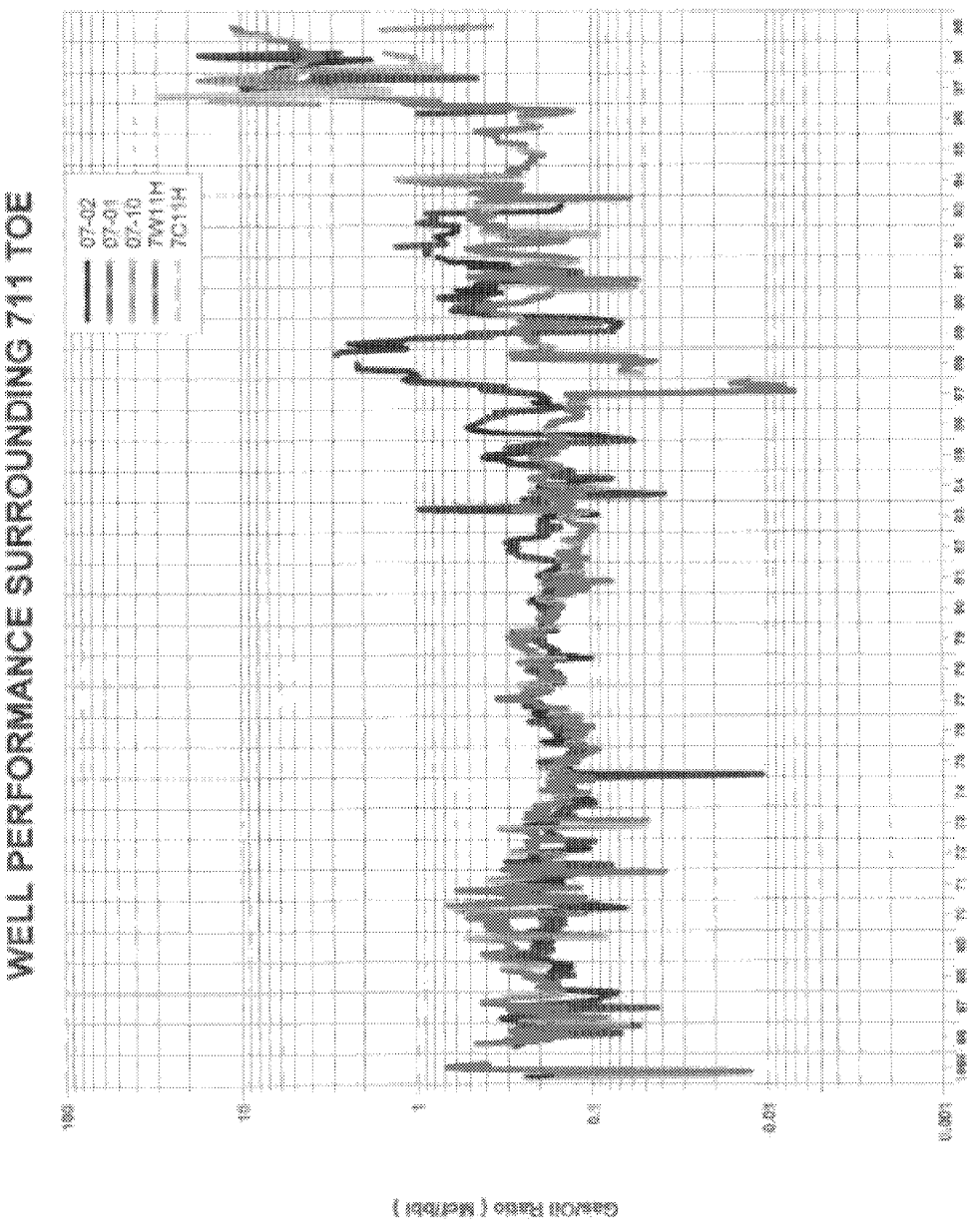

WELL PERFORMANCE SURROUNDING 711 TOE
07-02
07-01
07-10
7W11H
7C11H
Gas/Oil Ratio (Mcf/bbl)
100
10
1
0.1
0.01
0.001

FIGURE C.7

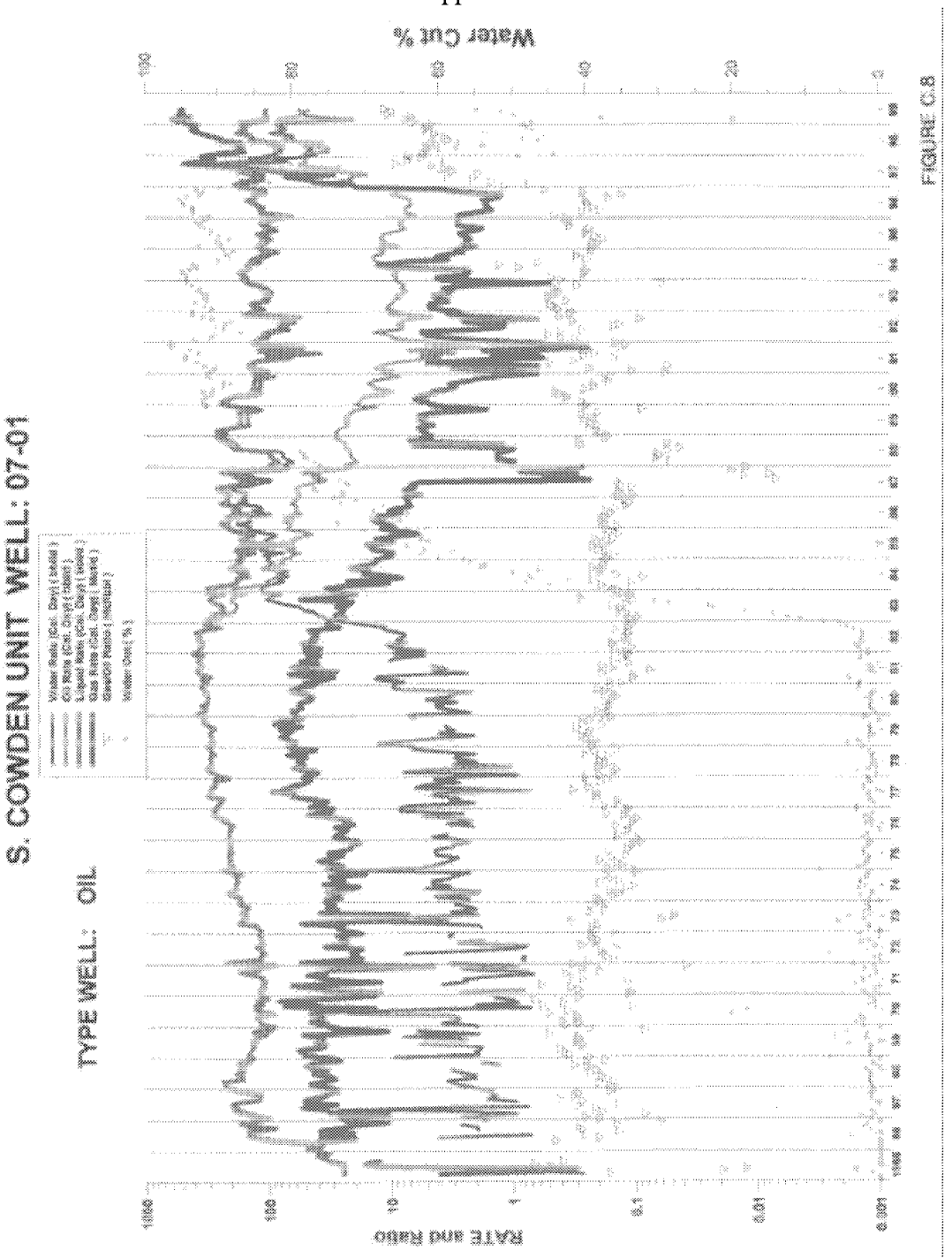
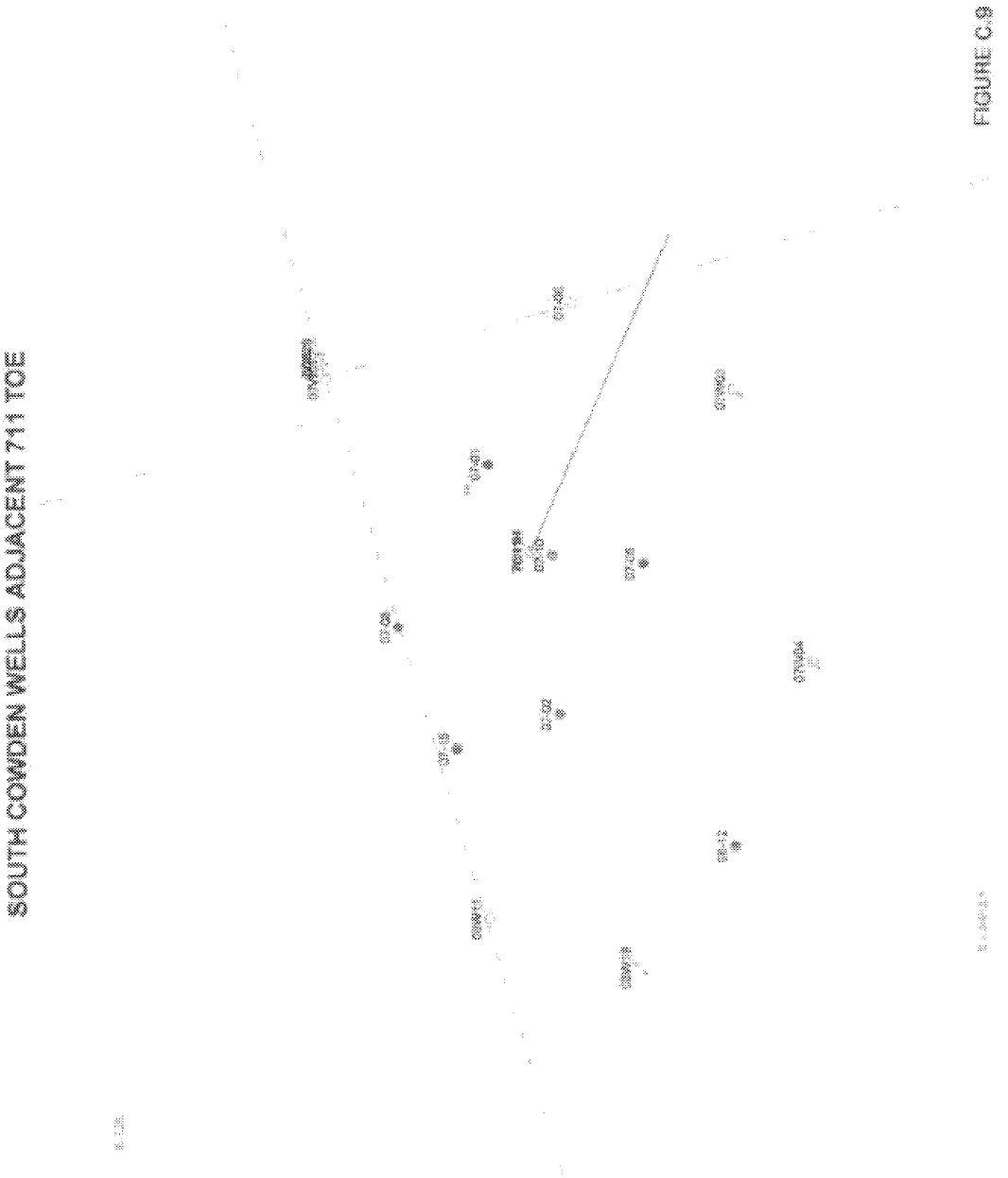
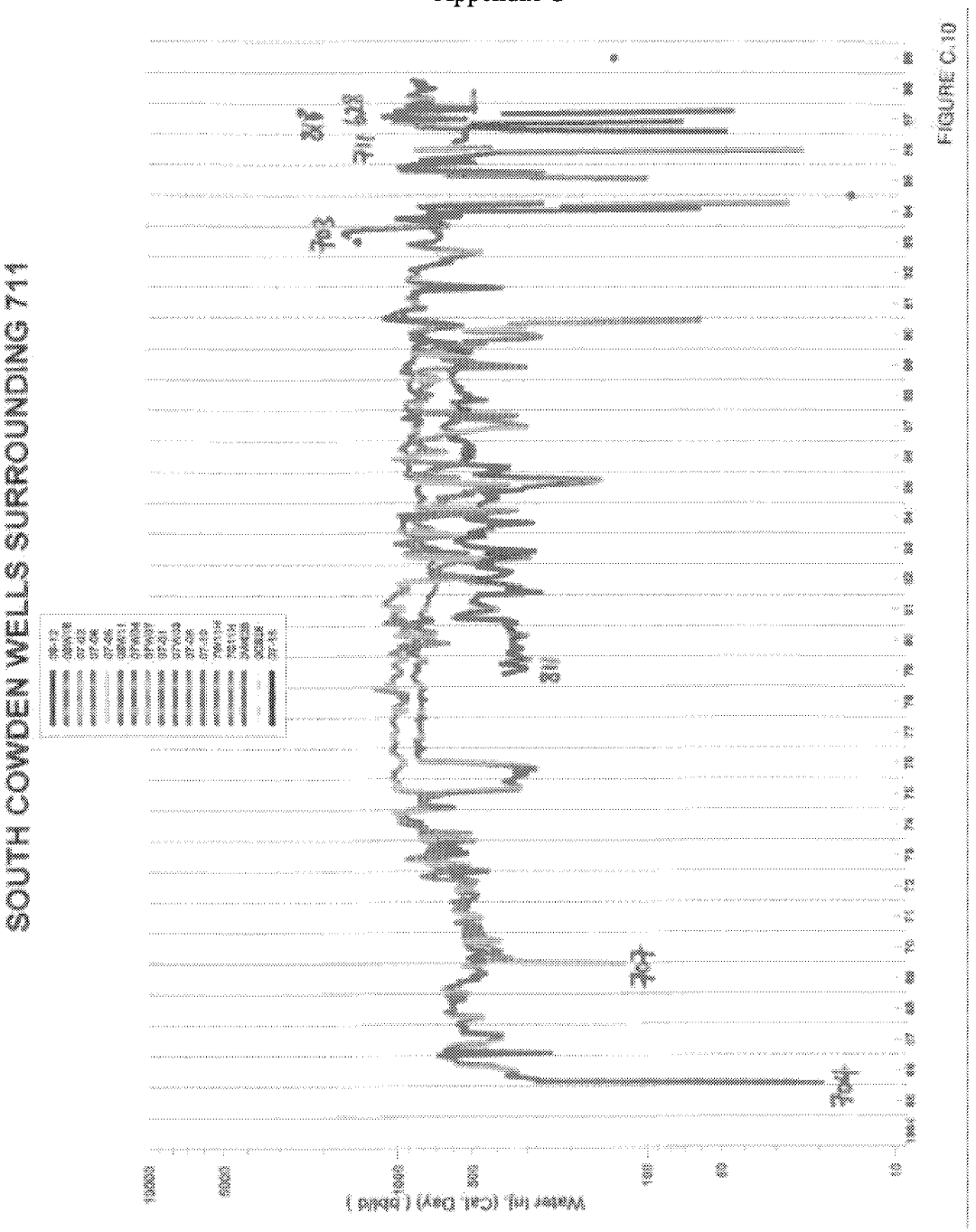

S. COWDEN UNIT WELL: 07-01
TYPE WELL: OIL
Water Cut %
RATE and Ratio
100
80
60
40
20
0
1000
100
10
1
0.1
0.01
0.001

FIGURE C.8


SOUTH COWDEN WELLS ADJACENT 711 TOE
FIGURE C-9


SOUTH COWDEN WELLS SURROUNDING 711
Water Inj. (Cal. Day) (bbl/d)
FIGURE C.10

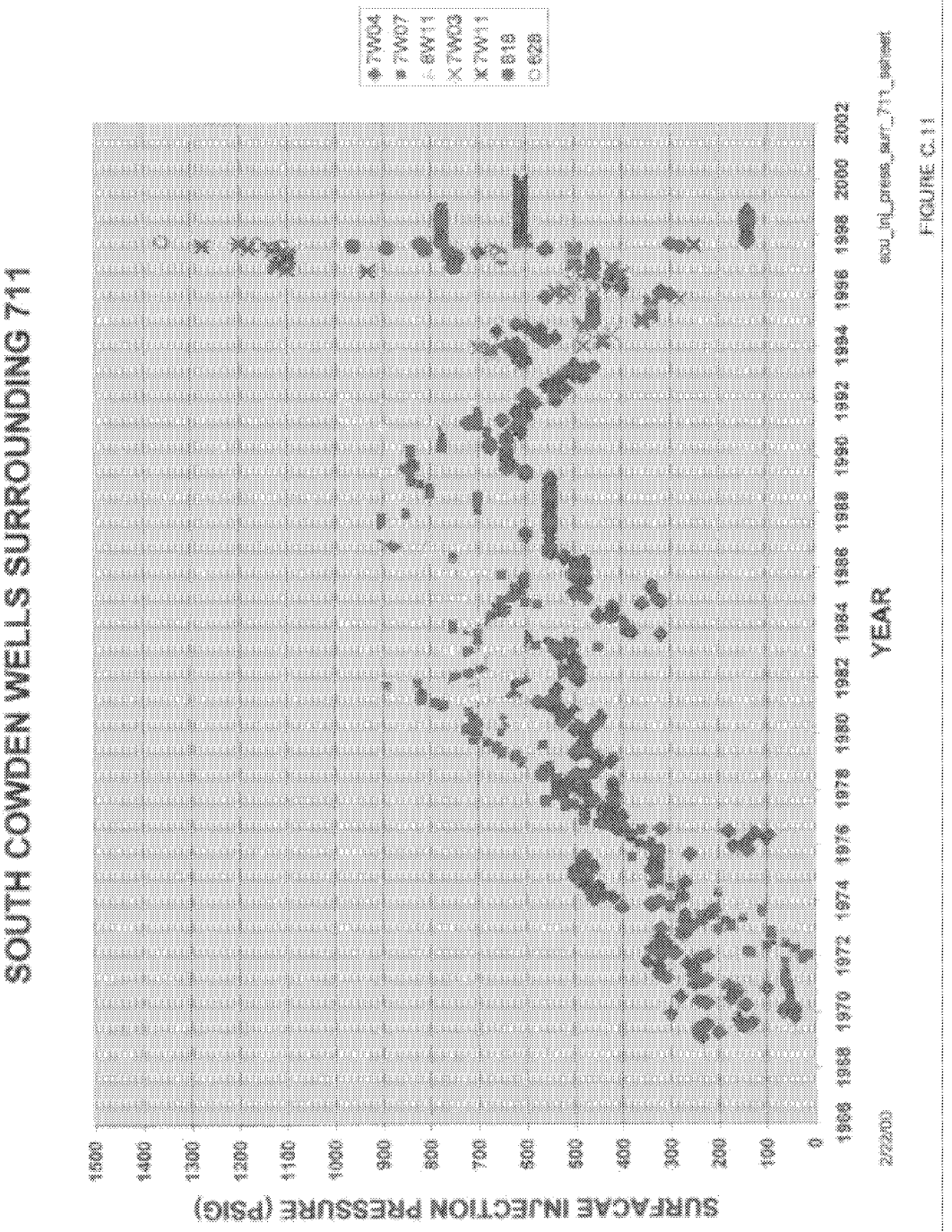
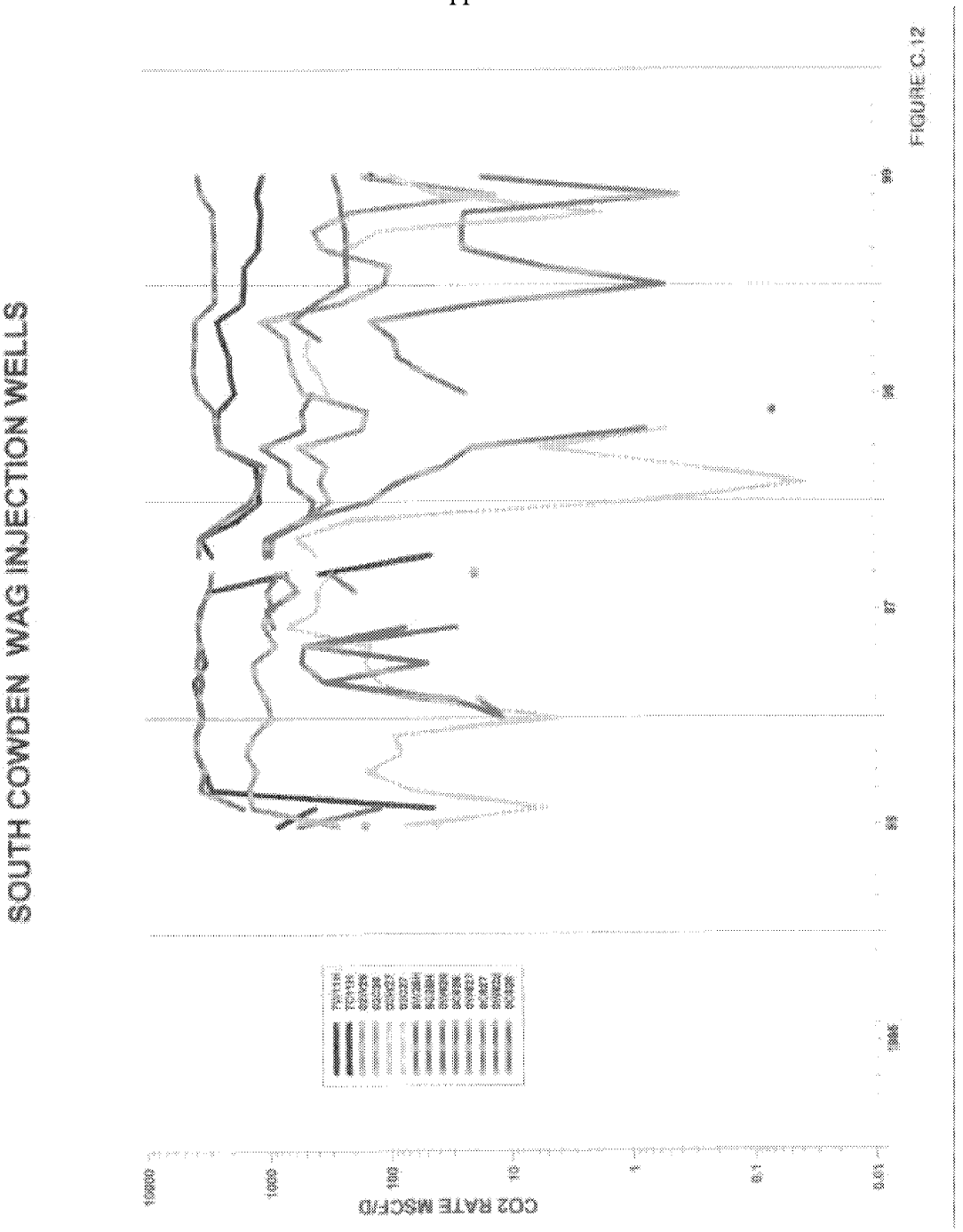
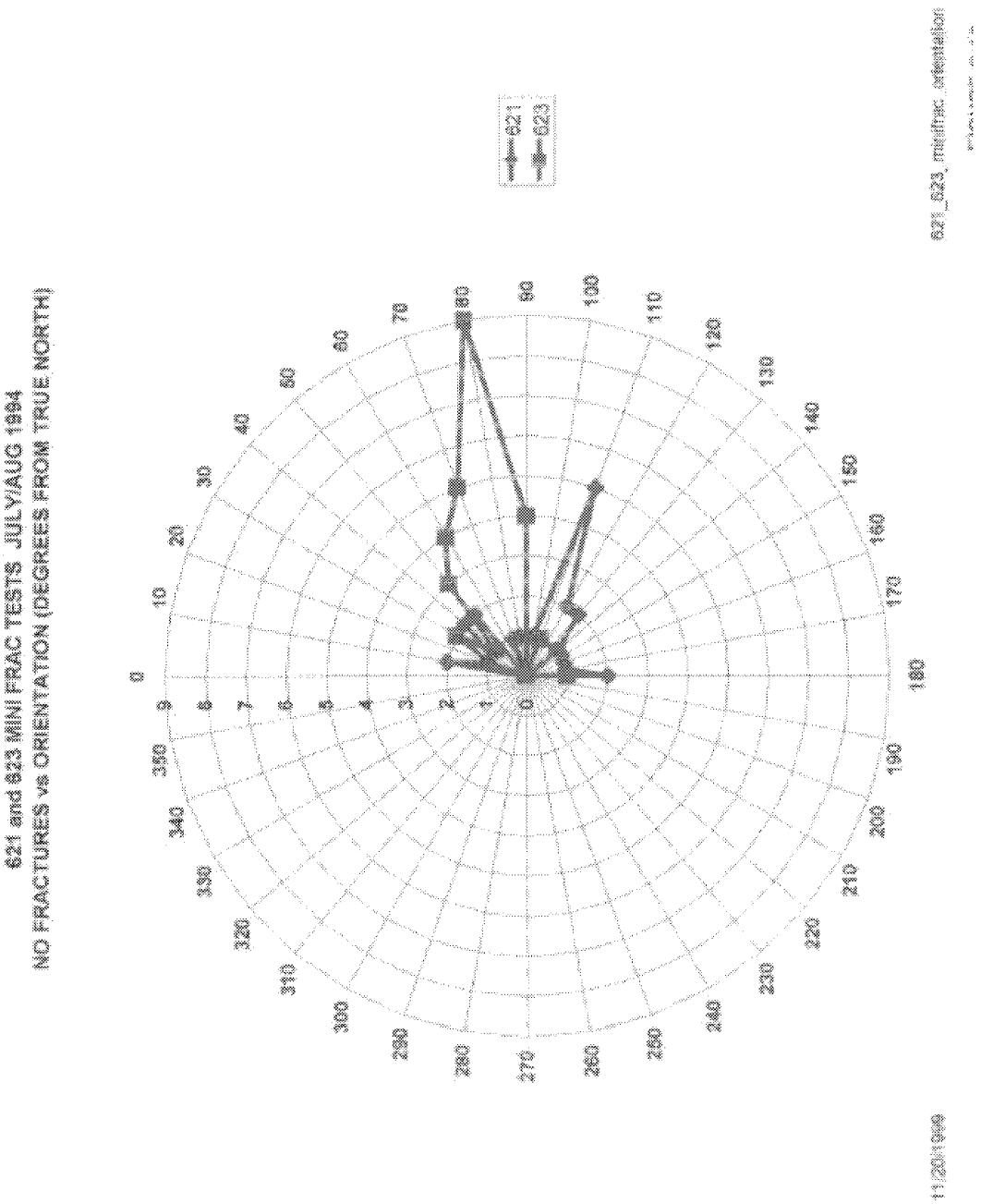

SOUTH COWDEN WELLS SURROUNDING 711
SURFACE INJECTION PRESSURE (PSIG)
YEAR
7W04
7W07
6W11
7W03
7W11
616
628
1500
1400
1300
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002

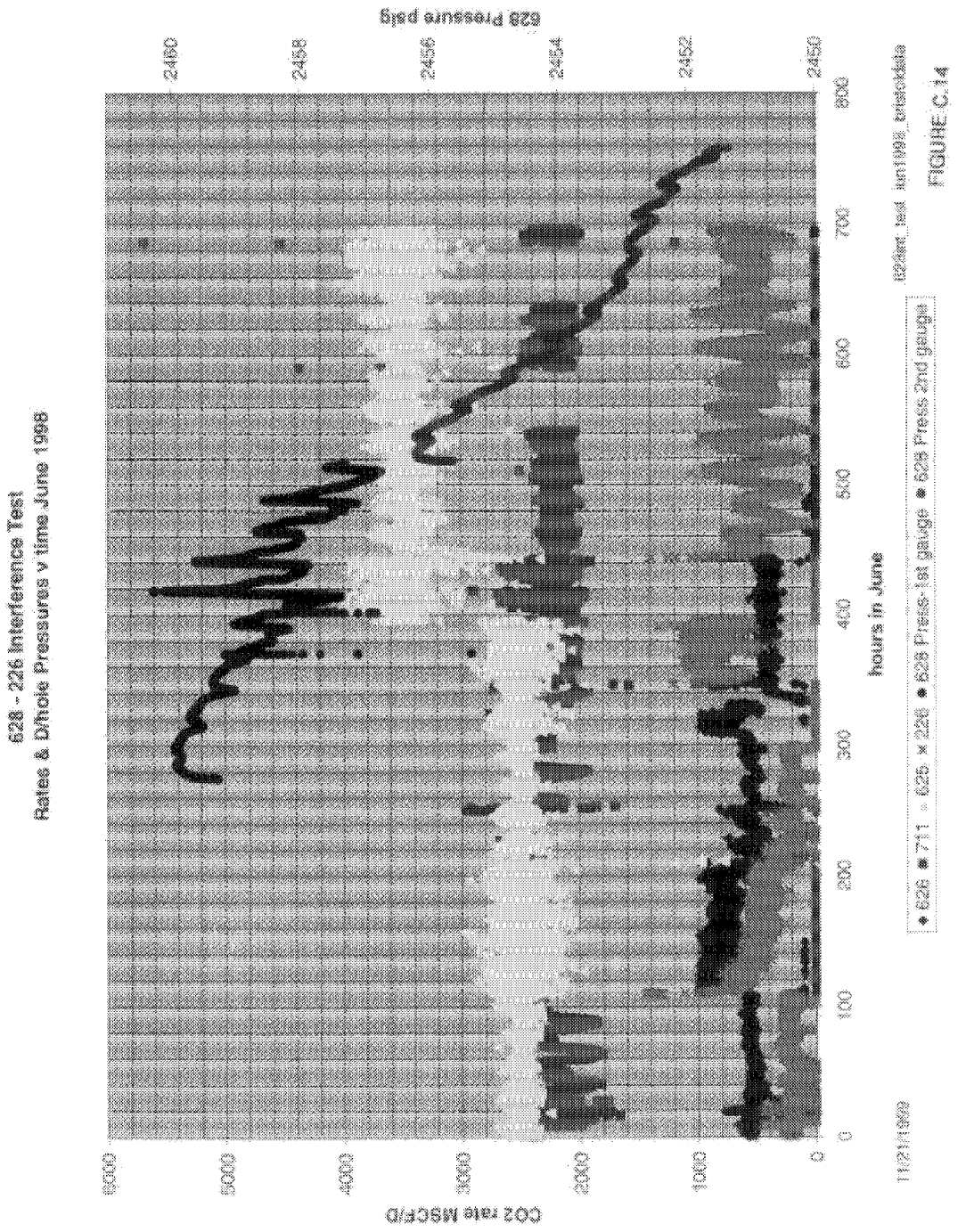
FIGURE C.11


SOUTH COWDEN WAG INJECTION WELLS
CO2 RATE MSCF/D
10000
1000
100
10
1
0.1
0.01
FIGURE C.12

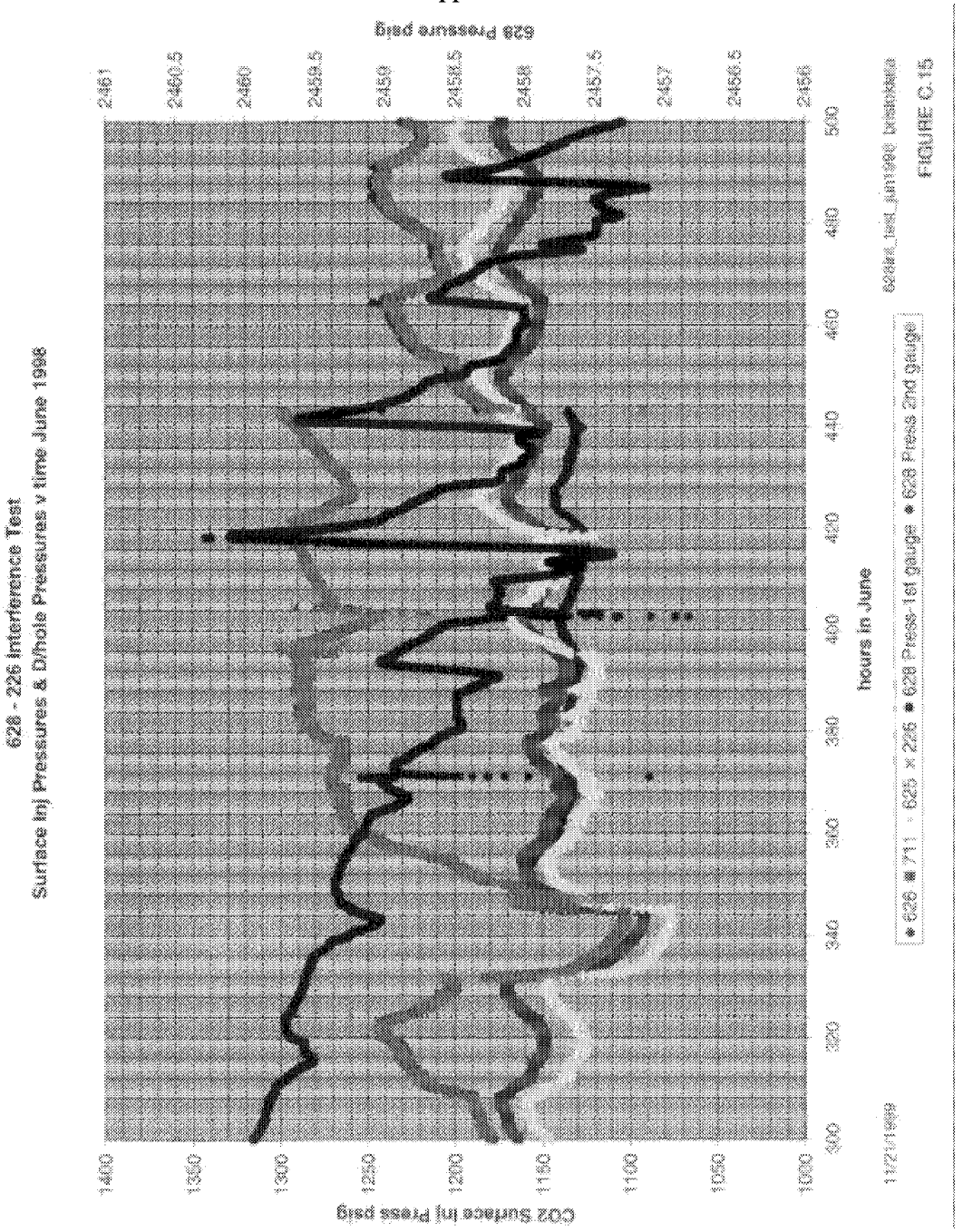
Appendix G


621 and 623 MINI FRAC TESTS JULY/AUG 1994
NO FRACTURES vs ORIENTATION (DEGREES FROM TRUE NORTH)
621
623
621_623_minifrac_orientation
11/28/1994

Appendix G


628 - 226 Interference Test
Rates & D/hole Pressures v time June 1998
628 Pressure psig
2460
2458
2456
2454
2452
2450
CO2 rate MSCF/D
6000
5000
4000
3000
2000
1000
0
hours in June
0
100
200
300
400
500
600
700
800
626 711 625 226 628 Press-1st gauge 628 Press 2nd gauge
FIGURE C.14

Appendix G


628 - 226 Interference Test
Surface Inj Pressures & D/hole Pressures v time June 1998
CO2 Surface Inj Press psig
628 Pressure psig
hours in June
628 Press 2nd gauge
628 Press-1st gauge
FIGURE C.15

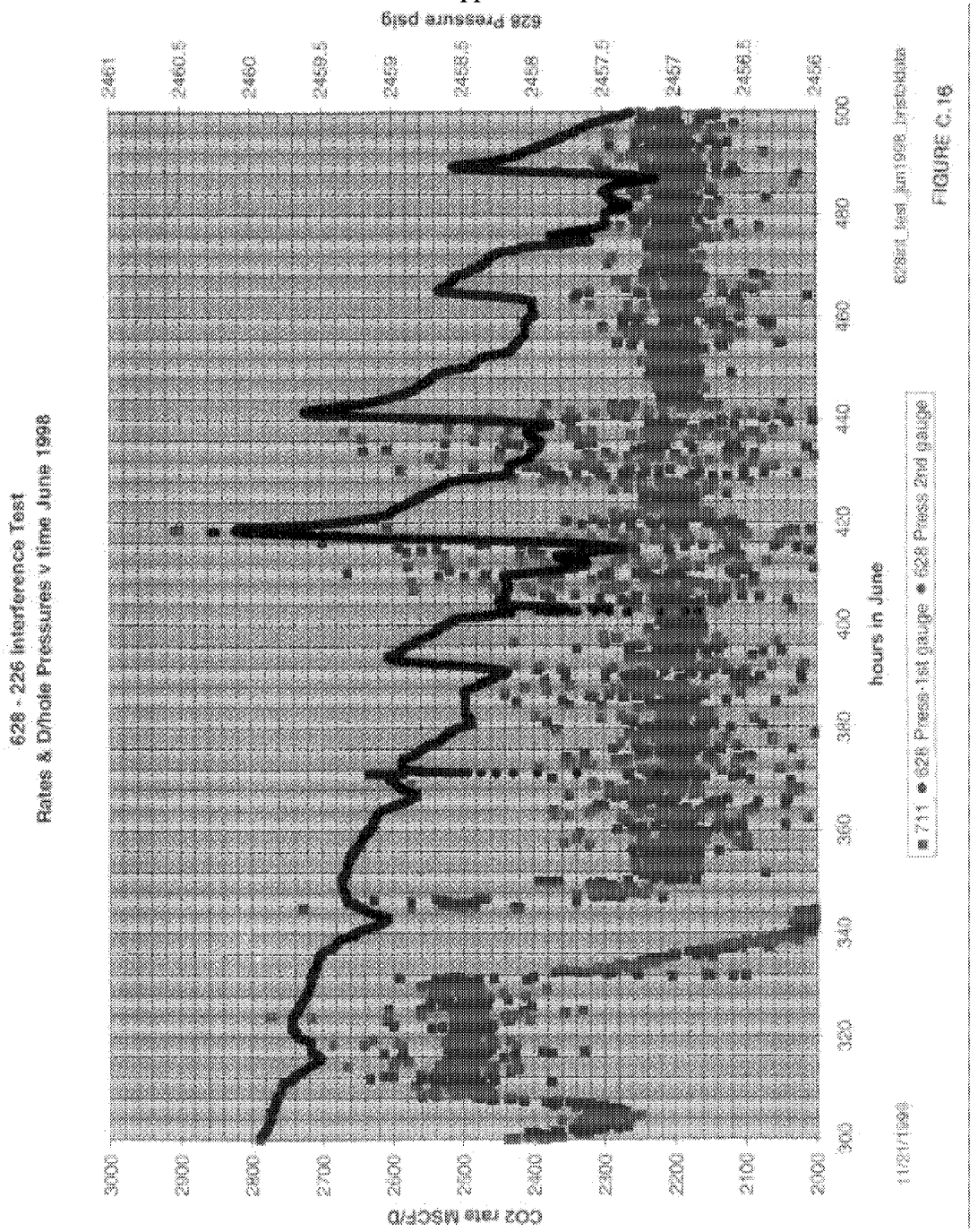
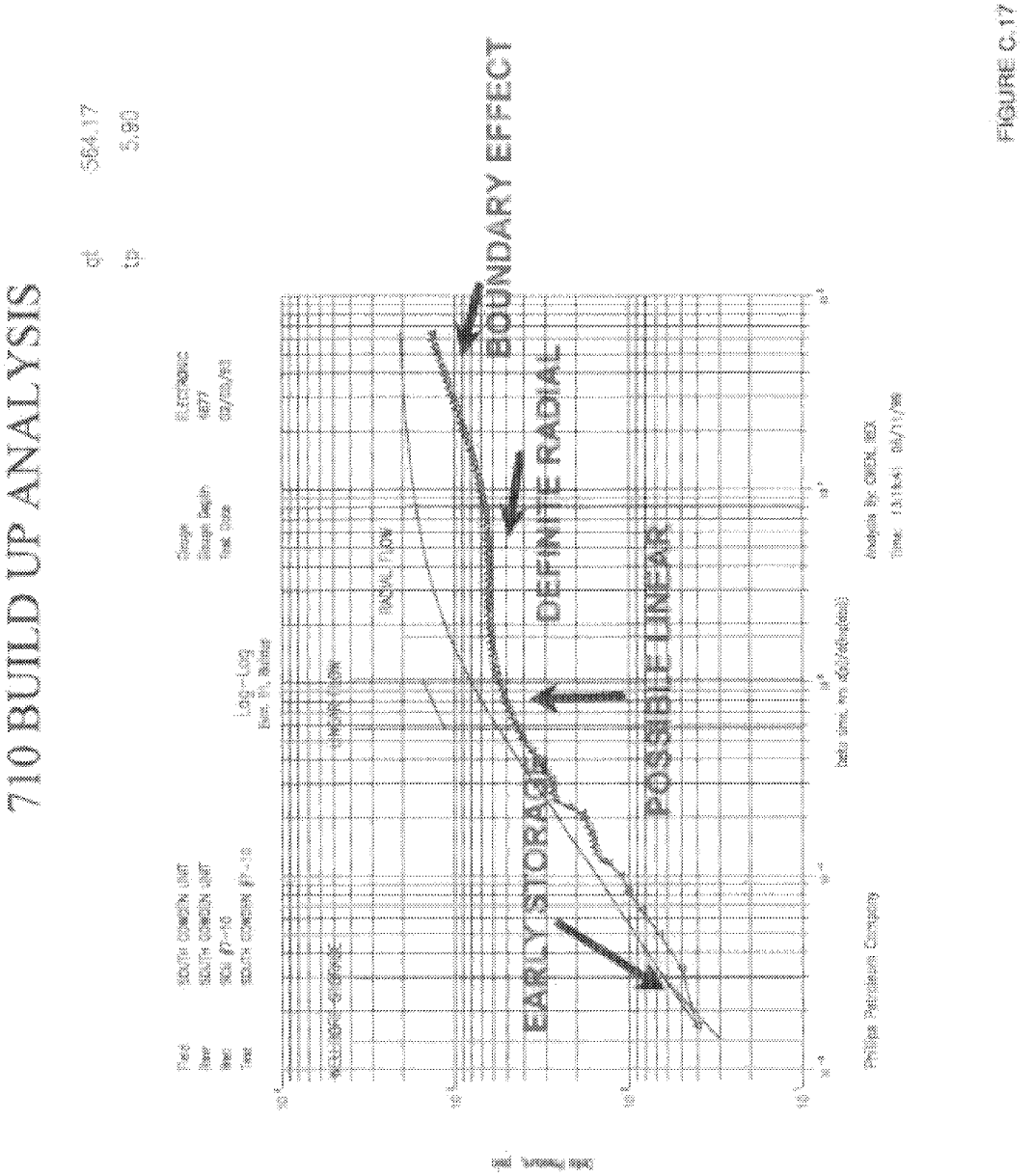

626 - 226 Interference Test
Rates & D/hole Pressures v time June 1998
626 Pressure psig
2461
2460.5
2460
2459.5
2459
2458.5
2458
2457.5
2457
2456.5
2456
CO2 rate MSCF/D
3000
2900
2800
2700
2600
2500
2400
2300
2200
2100
2000
300
320
340
360
380
400
420
440
460
480
500
hours in June
11/21/1998
■ 711 ● 626 Press-1st gauge ● 626 Press 2nd gauge
626int_test_jun1998_instadata

FIGURE C.16


710 BUILD UP ANALYSIS
qt 564.17
tp 5.80
BOUNDARY EFFECT
DEFINITE RADIAL
POSSIBLE LINEAR
EARLY STORAGE
Log-Log
Phillips Petroleum Company
FIGURE C.17

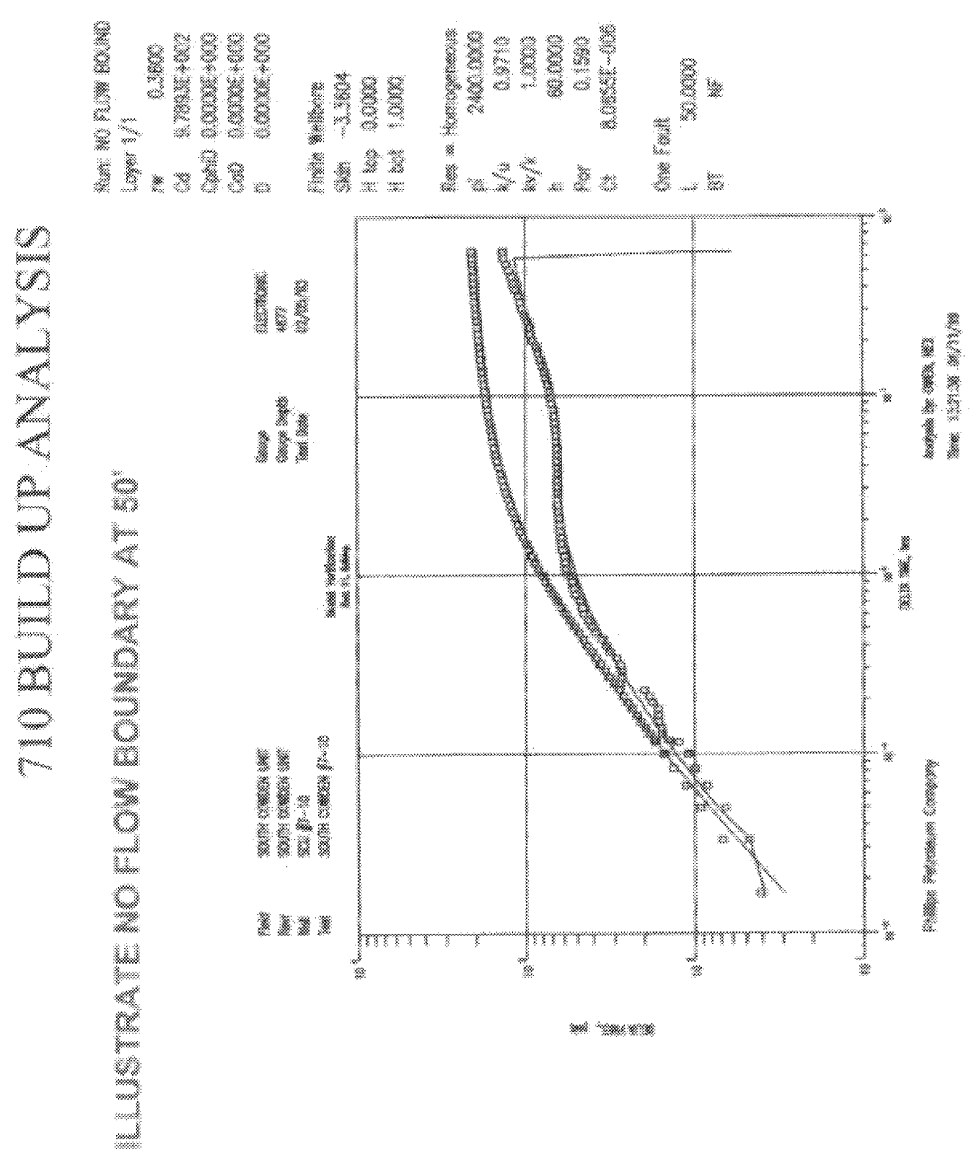


FIGURE C.18

Appendix G

SOUTH COWDEN WELLS NORTH OF 625 HORIZONTAL INJR

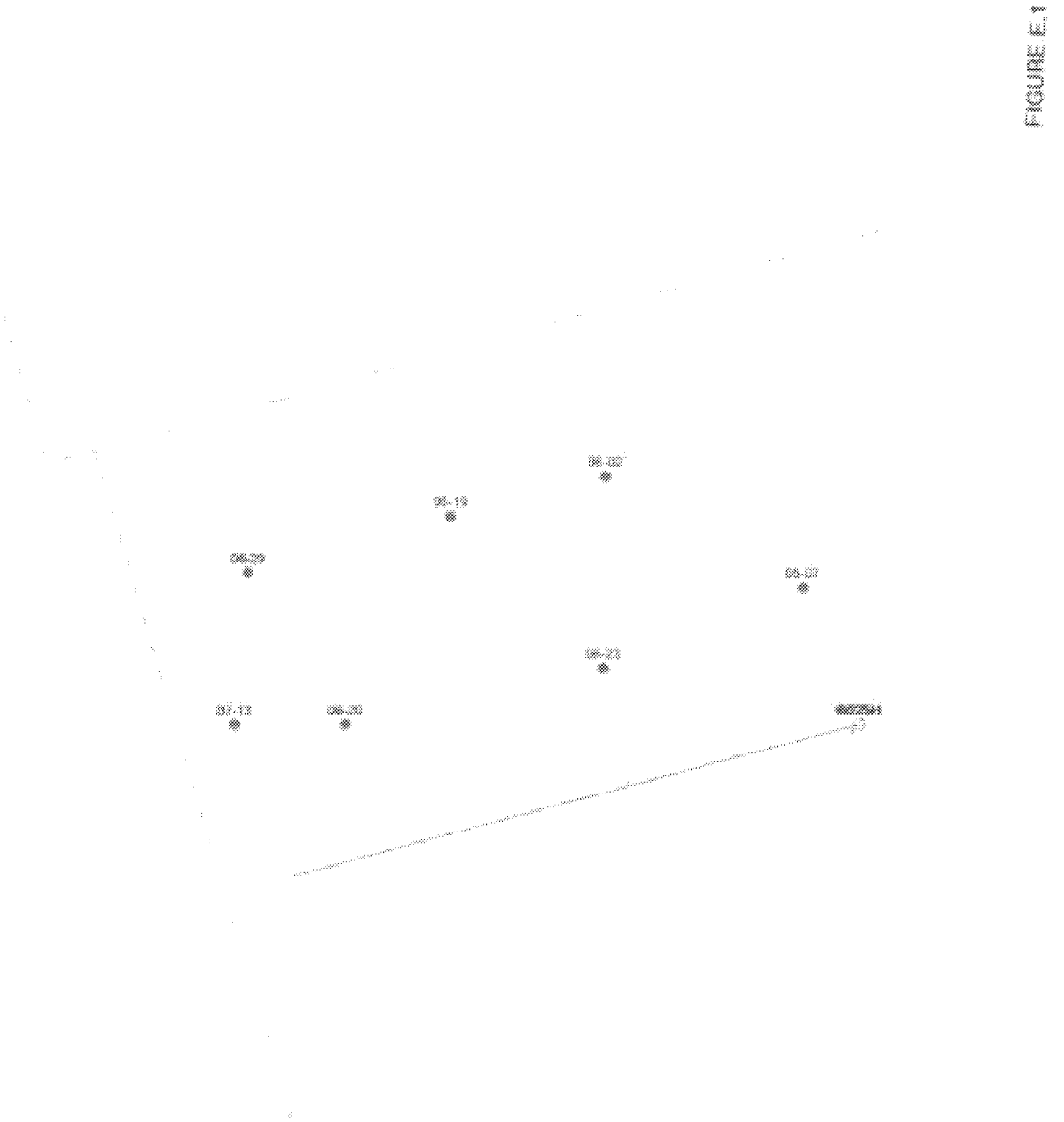


FIGURE E-1

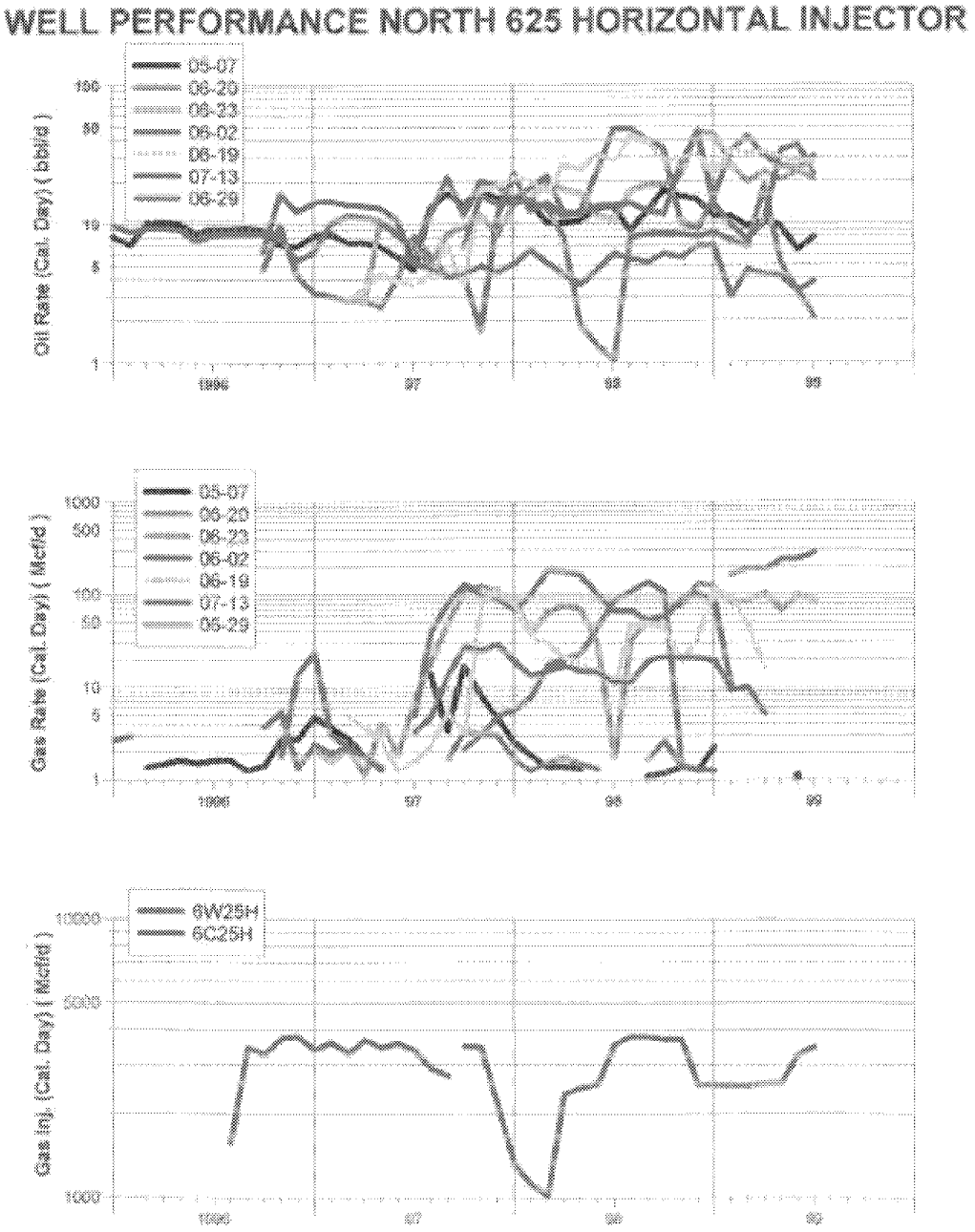

WELL PERFORMANCE NORTH 625 HORIZONTAL INJECTOR
05-07
06-20
06-23
06-02
06-19
07-13
05-29
Oil Rate (Cal. Day) (bbl/d)
100
50
10
5
1
1996
97
98
99
05-07
06-20
06-23
06-02
06-19
07-13
05-29
Gas Rate (Cal. Day) (Mcf/d)
1000
500
100
50
10
5
1
1996
97
98
99
9W25H
6C25H
Gas Inj. (Cal. Day) (Mcf/d)
10000
5000
1000
1996
97
98
99

FIGURE E-2

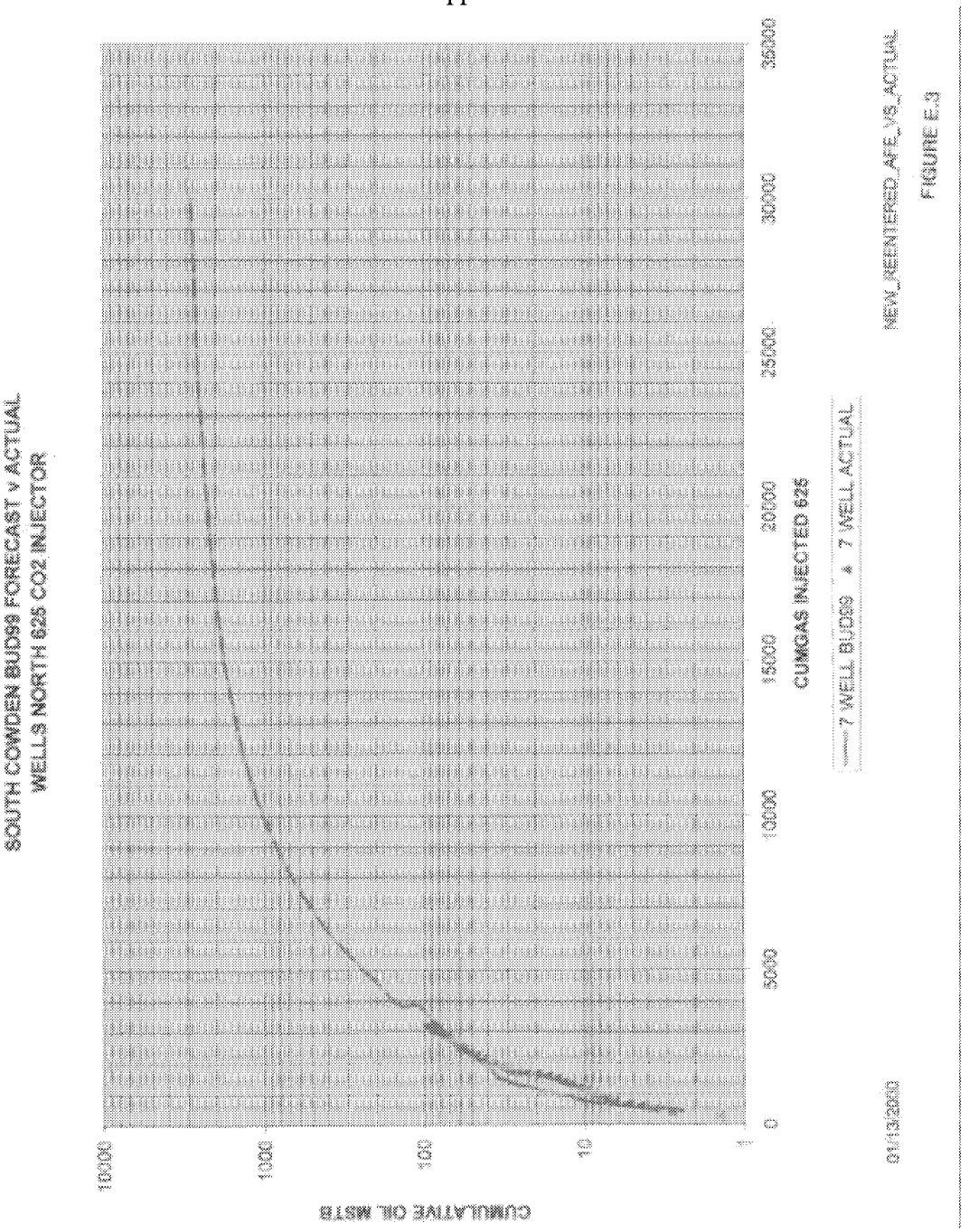

SOUTH COWDEN BUD99 FORECAST v ACTUAL
WELLS NORTH 625 CO2 INJECTOR
CUMULATIVE OIL MSTB
10000
1000
100
10
1
0
5000
10000
15000
20000
25000
30000
35000
CUMGAS INJECTED 625
7 WELL BUD99
7 WELL ACTUAL
01/13/2010
NEW_REENTERED_AFE_VS_ACTUAL

FIGURE E.3

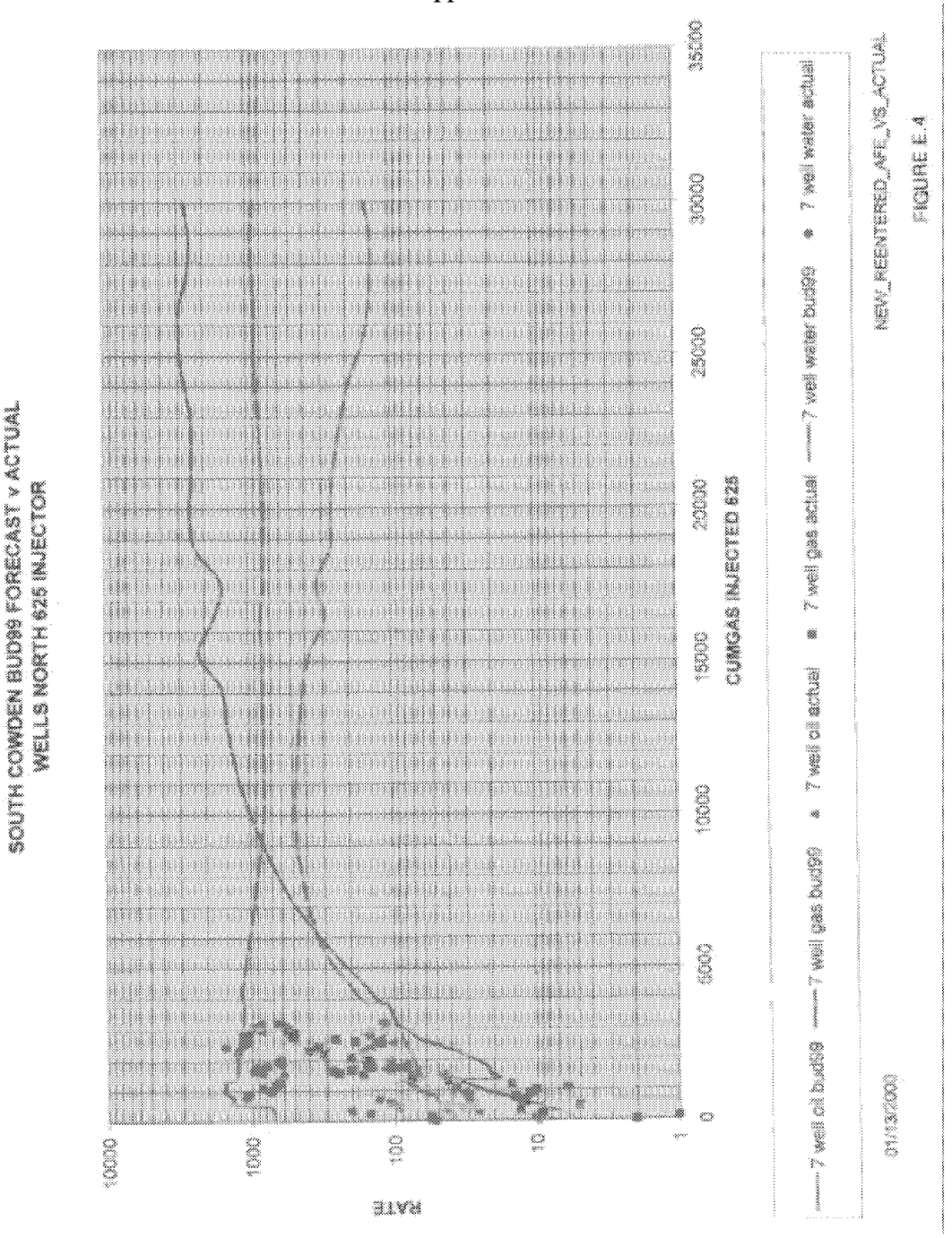

SOUTH COWDEN BUD99 FORECAST v ACTUAL
WELLS NORTH 625 INJECTOR
RATE
10000
1000
100
10
1
0
5000
10000
15000
20000
25000
30000
35000
CUMGAS INJECTED 625
7 well oil bud99
7 well gas bud99
7 well oil actual
7 well gas actual
7 well water bud99
7 well water actual
01/13/2003
NEW_REENTERED_AFE_VS_ACTUAL

FIGURE E.4

SOUTH COWDEN BUD99 FORECAST v ACTUAL
WELLS NORTH 625 INJECTOR
GOR SCF/STB
100000
10000
1000
100
0
5000
10000
15000
20000
25000
30000
35000
CUMGAS INJECTED 625
7 WELL GOR BUD99
7 WELL GOR ACTUAL
01/13/2000
NEW_PRINTFRIENDLY APE VS_ACTUAL

FIGURE E.6

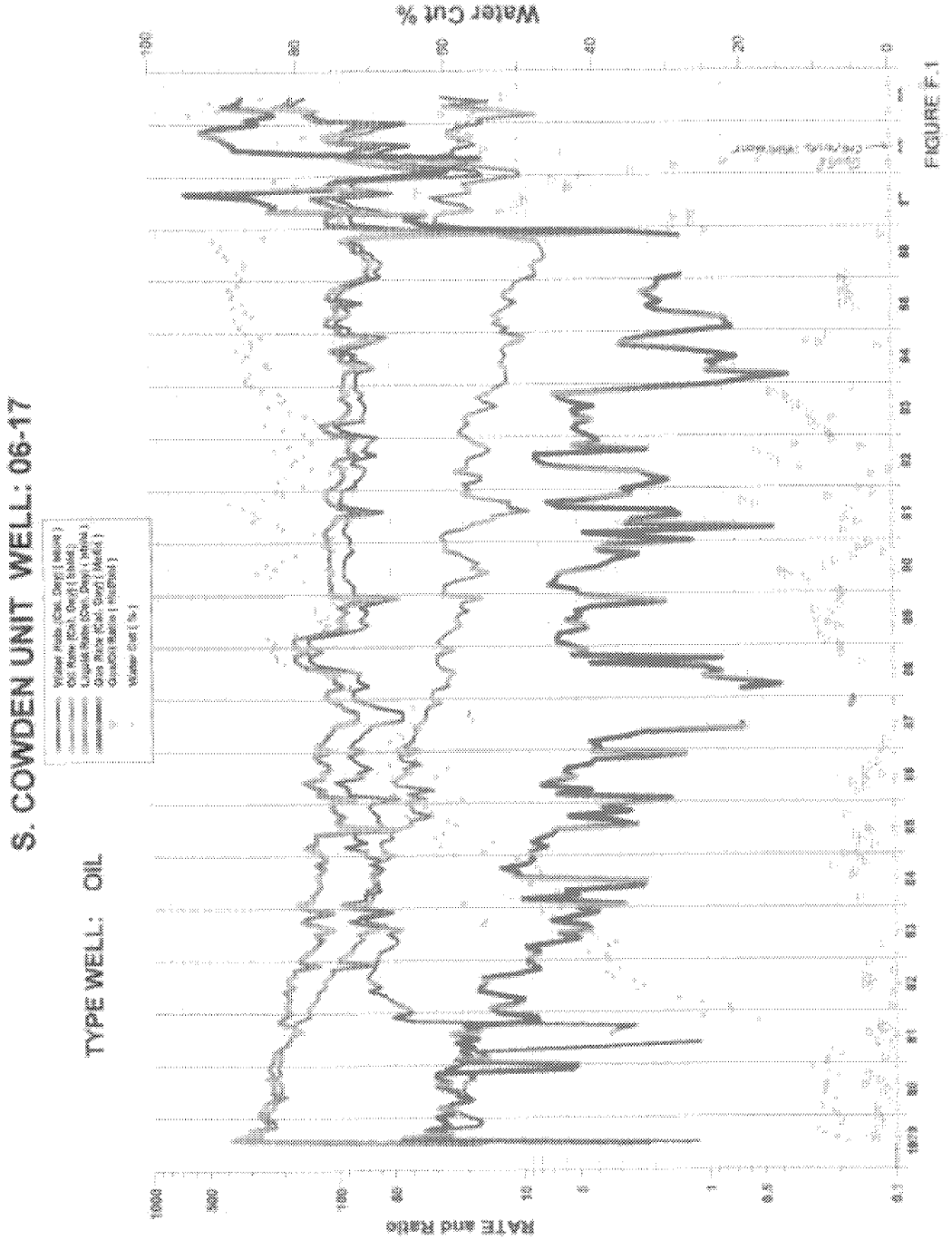

S. COWDEN UNIT WELL: 06-17
TYPE WELL: OIL
Water Cut %
RATE and Ratio
Water Cut (%)

FIGURE F-1

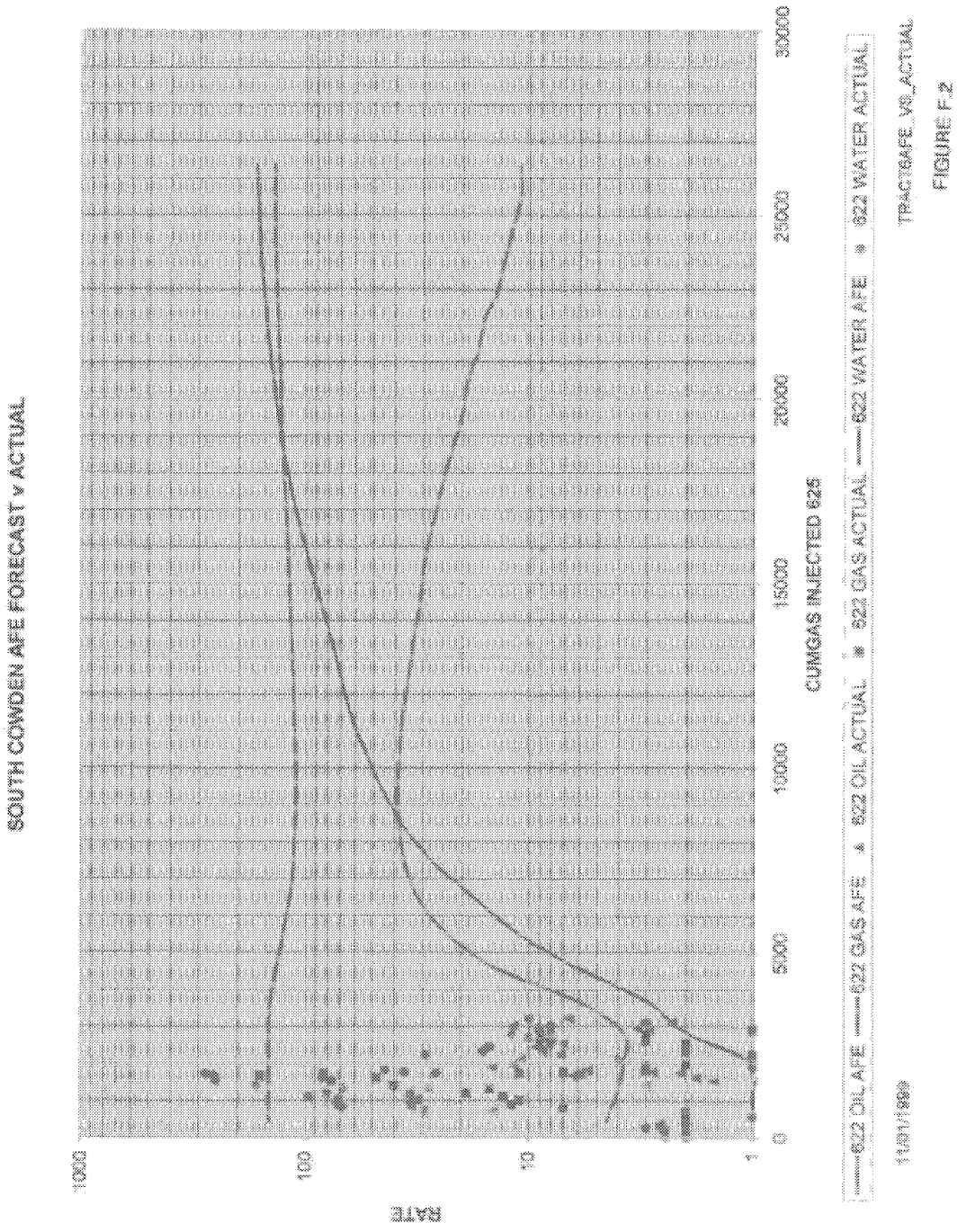

SOUTH COWDEN AFE FORECAST v ACTUAL
RATE
1000
100
10
1
0
5000
10000
15000
20000
25000
30000
CUMGAS INJECTED 625
622 OIL AFE
622 GAS AFE
622 OIL ACTUAL
622 GAS ACTUAL
622 WATER AFE
622 WATER ACTUAL
11/01/1999
TPACT6AFE_V6_ACTUAL

FIGURE F-2

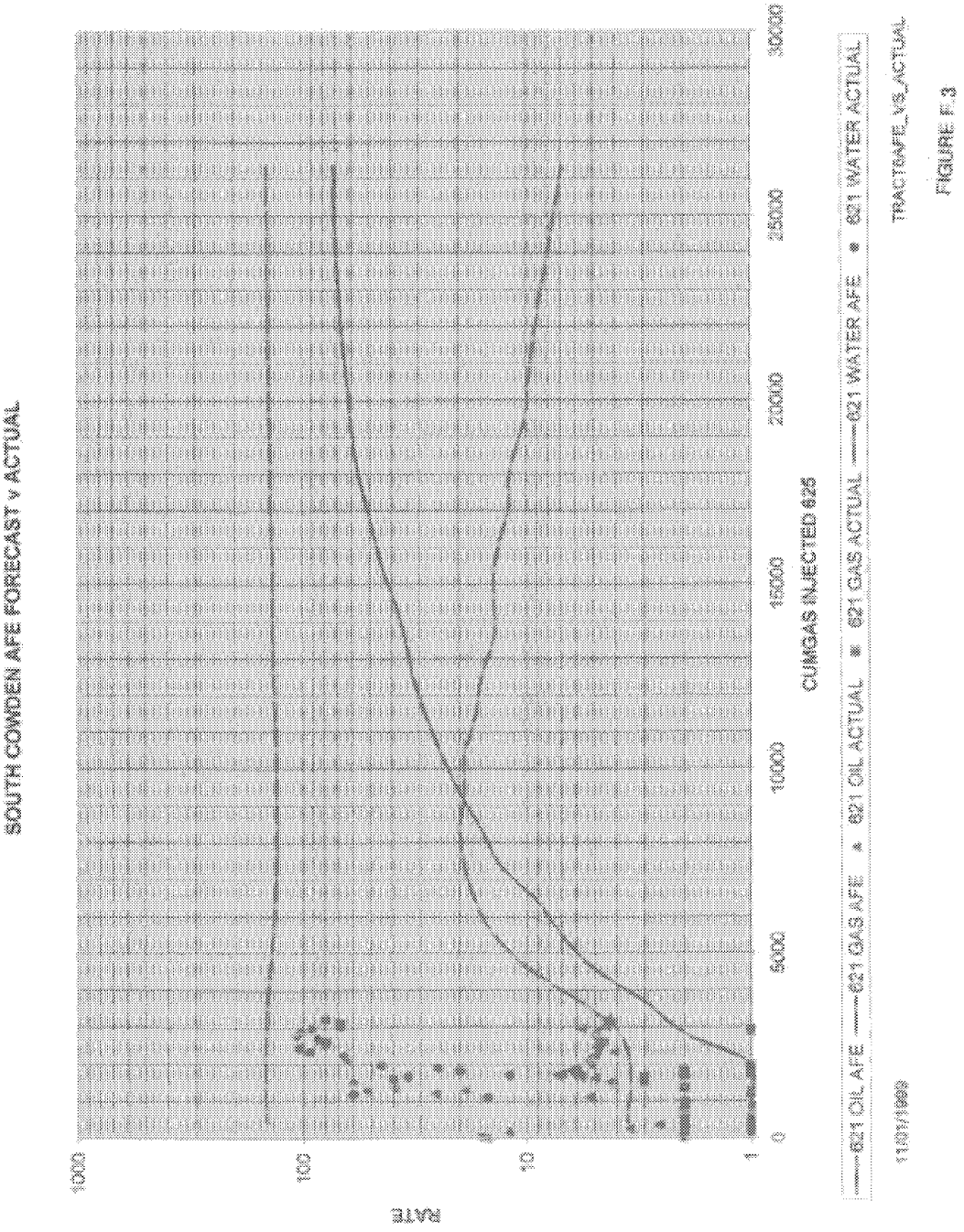

SOUTH COWDEN AFE FORECAST v ACTUAL
RATE
1000
100
10
1
0
5000
10000
15000
20000
25000
30000
CUMGAS INJECTED 625
621 OIL AFE
621 GAS AFE
621 OIL ACTUAL
621 GAS ACTUAL
621 WATER AFE
621 WATER ACTUAL
11/01/1999
TRACTOAFE_VS_ACTUAL

FIGURE E-3

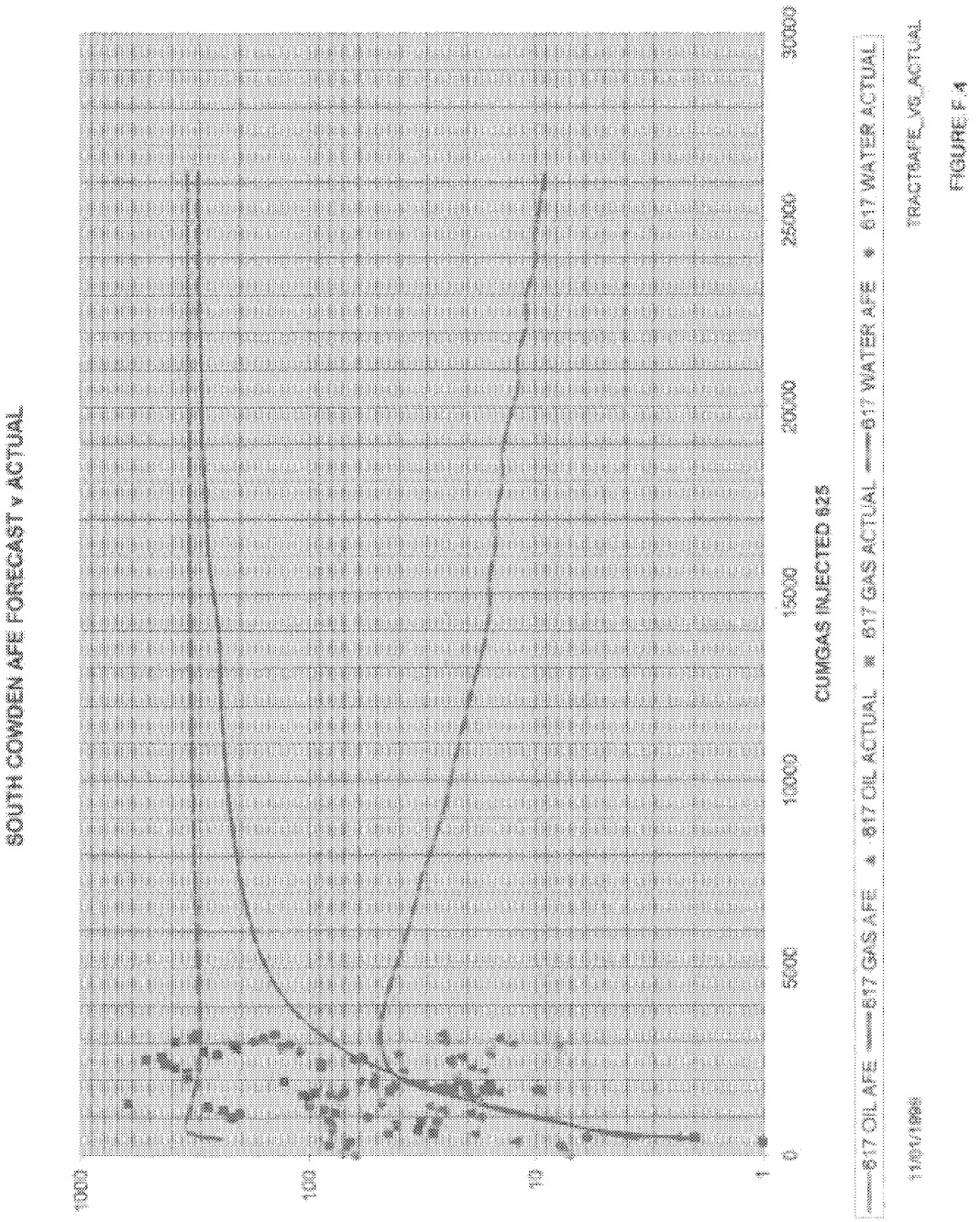

SOUTH COWDEN AFE FORECAST v ACTUAL
1000
100
10
1
0
5000
10000
15000
20000
25000
30000
CUMGAS INJECTED 625
617 OIL AFE
617 GAS AFE
617 OIL ACTUAL
617 GAS ACTUAL
617 WATER AFE
617 WATER ACTUAL
11/01/1998
TRACTRAFE_VS_ACTUAL

FIGURE F-1

Appendix G

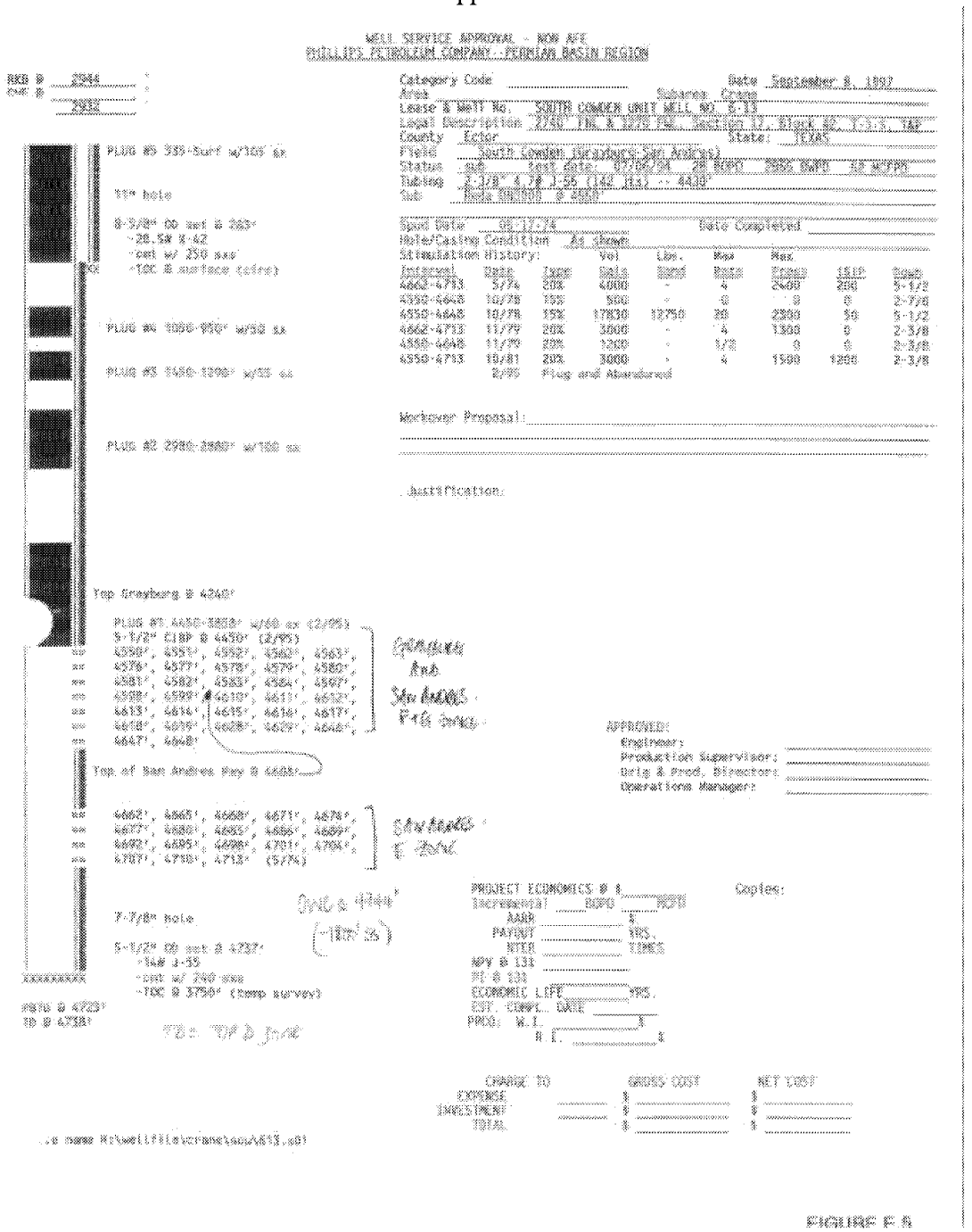


FIGURE # 6

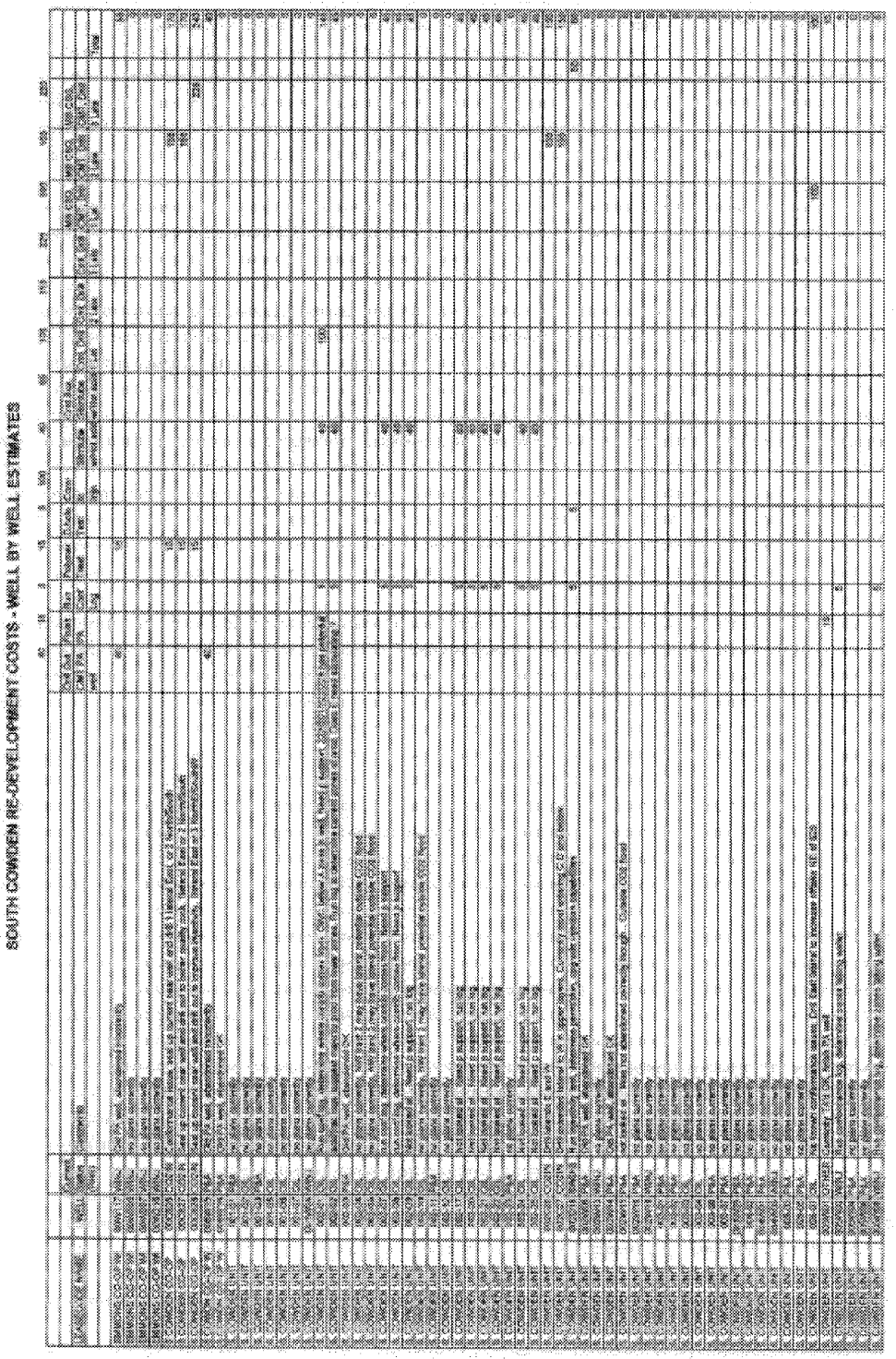


FIGURE G.1A

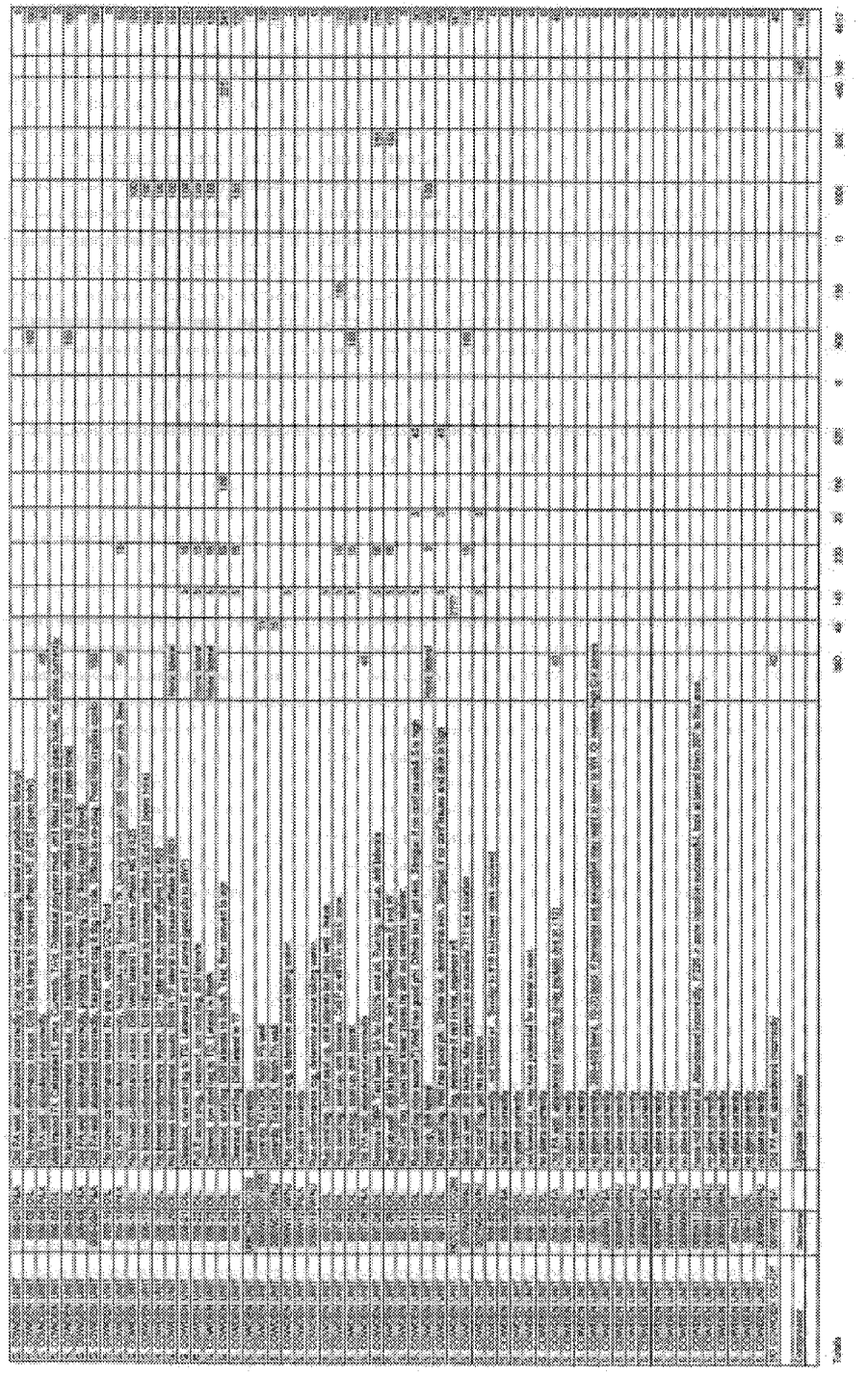


FIGURE G.1B

SOUTH COWDEN OPTIONS DEC1999

REDEVELOPMENT SENSITIVITIES

- SPLIT REDEVELOPMENT OPTIONS UP INTO PHASES 1, 2, 3, 4, 5, 6

1 = highest priority, 6 = least priority

- Phase I	Test lateral technology, improve offtake main CO2 area
- Phase II	Improve injectivity, reduce out of zone in CO2 injection wells and poorly PA'd wells.
	Increase water disposal capacity.
	Improve upper layer productivity Tract 2,7
- Phase III	Improve offtake surrounding 711, convert 624
- Phase IV	Improve productivity N and S 625
- Phase V	Improve productivity NE of 625
- Phase VI	Improve F zone productivity Tract 2

FIGURE G.2

Appendix G

SOUTH COWDEN PRELIMINARY SCHEDULE

Well	Type	Dates	DurN	Cost	Total Cost
RIG1 - Drill laterals/Improve in zone injection					
PHASE I - Test Lateral technology, monitor performance*					
		01-Jan-00			
006-20	lat	11-Jan-00	10	100	
006-22	lat	21-Jan-00	10	120	
006-23	lat	31-Jan-00	10	120	
007-13	lat	10-Feb-00	10	105	445
PHASE II - Improve injectivity, reduce out of zone injection					
		01-Apr-00			
002C26	lats	11-Apr-00	10	155	
002C27	lats	21-Apr-00	10	155	
00C628	lats	05-May-00	14	170	
00C627	lats	19-May-00	14	170	
00C628	lats	09-Jun-00	21	240	890
PHASE III - Upon successful 711 work, improve offtake surrounding well and convert 624					
		09-Jun-00			
007-09	lat	23-Jun-00	14	175	
007W03	lat	03-Jul-00	10	115	
007-02	lats	17-Jul-00	14	175	
007-08	lats	31-Jul-00	14	175	
007-05	lat	10-Aug-00	10	120	
006-29	lat	20-Aug-00	10	120	
006-24	lats	10-Sep-00	21	345	1225
PHASE IV - Improve productivity North and South of 625					
		10-Sep-00			
006-21	lat	20-Sep-00	10	120	
006-17	lat	30-Sep-00	10	100	
006-02	lat	10-Oct-00	10	100	
006-07	lat	20-Oct-00	10	100	
006-19	lat	30-Oct-00	10	100	520
PHASE V - Improve Productivity NE of 625					
		30-Oct-00			
006-14	lat	09-Nov-00	10	100	
006-06	lat	19-Nov-00	10	100	200
PHASE VI - Improve F zone offtake in Tract 2					
		19-Nov-00			
002-01	lat	29-Nov-00	10	145	145
RIG 2 - Plug and Abandon Wells, 711 conformance					
PHASE II - Reduce out of zone injection (entering P&A wells requires justification thro' sim work)					
		01-Apr-00			
006W15	PA	11-Apr-00	10	40	
00W117	PA	21-Apr-00	10	55	
007W07	PA	01-May-00	10	40	
007C11H	log/Tbg Cost	15-May-00	14	147	
006-13	PA	25-May-00	10	55	
007-06	PA	04-Jun-00	10	40	
005-14	PA	14-Jun-00	10	40	
005W01	TA-PA	24-Jun-00	10	15	
006-04	PA	04-Jul-00	10	40	
006W03	TA-PA	14-Jul-00	10	15	
006W07	TA-PA	24-Jul-00	10	15	
006-09A	Fish/PA	13-Aug-00	20	100	602
ADDITIONAL WORK					
		01-Jan-00			
Gas Comp	Upg	15-Mar-00	74	145	145
PHASE II					
002D18	Test/Upg	Jun-00	??	60	60

** - note compressor upgrade not complete until mid march.*
Estimated gas rates from lease will exceed current 1200 MSCF/D compressor limit w/ laterals.
Will need to shut in high CO2 rate wells and periodically test 4 lateral wells early 2000.

01/24/2000 wellbywell_with_tract2_stimtube

FIGURE G.3A

SOUTH COWDEN PRELIMINARY SCHEDULE

Other cost - Phase II logging/stimulation

Well	Type	Dates	Dur/N	Cost	Total Cost
		01-Jun-00			
007W04	log/tst	06-Jun-00	5	10	
007-15	log/tst/Stim	13-Jun-00	7	50	
007-12	log/tst/Stim	20-Jun-00	7	50	
007-10	log	22-Jun-00	2	5	
007-01	log	24-Jun-00	2	5	
006W11	log	26-Jun-00	2	5	
005W08	log	28-Jun-00	2	5	
005W02	log	30-Jun-00	2	5	
002-25	log/stm	07-Jul-00	7	45	
002-24	log/stm	14-Jul-00	7	45	
002-22	log/stm	21-Jul-00	7	45	
002-21	log/stm	28-Jul-00	7	45	
002-20	log/stm	04-Aug-00	7	45	
002-17	log/stm	11-Aug-00	7	45	
002-09	log/stm	18-Aug-00	7	45	
002-08	log/stm	25-Aug-00	7	45	
002-07	log/stm	01-Sep-00	7	45	
002-02	log/stm	08-Sep-00	7	45	585

FIGURE G-pp

SOUTH COWDEN PHASE COST ESTIMATES - RECYCLE TO 8.6 MM/D

					GROSS	
						Running
CAPITAL	RIG1	RIG2	OTHER	COMPLETE	TOTAL	Total
	Cost	Cost	Cost			
Upg Compr 4.5 MMCF/D			145	15-Mar-00	145	145
PHASE I	445	0		10-Feb-00	445	590
PHASE II + 218Upg	890	602	60	13-Aug-00	1552	2142
PHASE II (Other)			585	8-Sep-00	585	2727
PHASE III	1225	0		10-Sep-00	1225	3952
PHASE IV	520	0		30-Oct-00	520	4472
PHASE V	200	0		19-Nov-00	200	4672
PHASE VI	145	0		29-Nov-00	145	4817
Upg Compr 8.6 MMCF/D			145	var**	145	4962
Total						4962

2/22/00

wellbywell_with_tract2_stimtube

FIGURE G.4

SOUTH COWDEN CO2 OPTIONS (PRELIM) - COMPRESSOR 8.6 MMSCF/D, OPEX $1.3MM/YR

Co2 Flood Simulation File	Gross Capital 2000 $MM	DOE CO2 Opx 2000 $MM	Economic Aband Year	Economic Gross Recovery MMSTB	Comments	COMPRESSOR UPGRADE YEAR	COMPRESSOR CAPITAL $MM
SOUTH COWDEN UNIT RECOVERY compared with w/flood as base case							
Orig AFE			2025	12.34	Gen Opex used $1.0 mm/yr (declining)		
scu_as_is	0.15	0.31	2013	3.06	As is situation. Current CO2 injn and Productivity. Gen Opex $1mm/yr (99)		
option2u	2.73	0.70	2015	7.71	Invest Phase II (no DOE), Comp 8.6MSCF/D, Gen Opex $1.3mm/yr.	2002	145
option3u	4.10	0.87	2011	6.50	Invest Phase III (no DOE), Comp 8.6MSCF/D, Gen Opex $1.3mm/yr.	2000	145
option4u	4.62	0.88	2010	6.35	Invest Phase IV (no DOE), Comp 8.6MSCF/D, Gen Opex $1.3mm/yr.	2000	145
option5u	4.82	0.88	2011	6.84	Invest Phase V (no DOE), Comp 8.6MSCF/D, Gen Opex $1.3mm/yr.	2000	145
option6u	4.96	0.88	2011	6.87	Invest Phase VI (no DOE), Comp 8.6MSCF/D, Gen Opex $1.3mm/yr.	2000	145

2/22/00

wellbywell_with_tract2_stimt.xls

FIGURE G.5

SOUTH COWDEN OPTIONS DEC1999

RECOMMENDED OPTION

PHASE I

- UPGRADE COMPRESSOR TO 4.5 MMSCF/D
- DRILL 4 LATERALS EARLY 2000
  620, 622, 623, 713
- MONITOR PERFORMANCE (proceed with phase II?)

PHASE II

- IMPROVE INJECTIVITY IN ZONE
  SEAL UP 226,227,626,627,628 IN NEAR WELL AREA
  & DRILL LATERALS
- IMPROVE TRACT 2 PRODUCTIVITY IN ZONE
  TEST/LOG/STIMTUBE/HOT ACID 715,712, 225,224, 222,221,220,217
  209,208,207,202
- P&A CORRECTLY 11 WELLS (SOME CURRENTLY TA) - requires justification
- RELOG 711 AND RESOLVE CONFORMANCE
- TEST 218D AND UPGRADE TO HANDLE LARGER
  DISPOSAL RATES.

FIGURE G.6

Appendix G

SOUTH COWDEN SCHEDULE

	Well	Type	Dates	Dur/M	Cost-latest	Total Cost Gross
UPGRADE COMPRESSOR	COMPRESSOR UPGRADE YR 2000					
	Gas Comp	Upg_4.5	15-Mar-00	74	148	148
PHASE I	RIG 1 - Test lateral technology, monitor performance*					
			15-Feb-00			
	006-20	lat	28-Feb-00	10	100	
	006-33	lat	9-Mar-00	10	120	
	007-13	lat	19-Mar-00	10	105	
	006-22	lat	29-Mar-00	10	126	446
PHASE II	RIG 1 - Improve productivity, injectivity, reduce out of zone injection					
			1-May-00			
	002D18	Test/Upg	11-May-00	10	80	
	002C26	lats	21-May-00	10	156	
	002C27	lats	31-May-00	10	156	
	00C826	lats	14-Jun-00	14	176	
	00C827	lats	28-Jun-00	14	176	
	00C828	lats	19-Jul-00	21	249	
	007C11R	[illegible]	2-Aug-00	14	147	
	007W04	log/tst	7-Aug-00	5	10	
	007-15	log/tst/Strm	14-Aug-00	7	80	
	007-12	log/tst/Strm	21-Aug-00	7	80	
	007-10	log	23-Aug-00	2	6	
	007-01	log	25-Aug-00	2	6	
	006W11	log	27-Aug-00	2	6	
	005W08	log	29-Aug-00	2	6	
	006W02	log	31-Aug-00	2	6	
	002-28	log/strm	7-Sep-00	7	45	
	002-24	log/strm	14-Sep-00	7	45	
	002-22	log/strm	21-Sep-00	7	45	
	002-21	log/strm	28-Sep-00	7	45	
	002-20	log/strm	8-Oct-00	7	45	
	002-17	log/strm	12-Oct-00	7	45	
	002-09	log/strm	19-Oct-00	7	45	
	002-08	log/strm	26-Oct-00	7	45	
	002-07	log/strm	2-Nov-00	7	45	
	002-02	log/strm	9-Nov-00	7	45	1582
	RIG 2 - PA wells					
			1-May-00			
	006W16	PA	11-May-00	10	40	
	006W17	PA	21-May-00	10	55	
	007W07	PA	31-May-00	10	40	
	006-13	PA	10-Jun-00	10	55	
	007-06	PA	20-Jun-00	10	40	
	008-14	PA	30-Jun-00	10	40	
	005W01	TA-PA	10-Jul-00	10	15	
	008-04	PA	20-Jul-00	10	40	
	006W03	TA-PA	30-Jul-00	10	15	
	006W07	TA-PA	9-Aug-00	10	15	
	008-09A	Flash/PA	29-Aug-00	20	100	455
UPGRADE COMPRESSOR	COMPRESSOR UPGRADE YR 2002					
	Gas Comp	Upg_6.6	2002	74	148	148
	TOTALS yr2000			426	2727	2727
	TOTALS yr2002			74	148	148
	TOTALS			500	2872	2872

** - note compressor upgrade to 4.5 MMSCF/D complete mid march.*
Estimated gas rates from leases will exceed current 1200 MSCF/D compressor limit w/ laterals.
Will need to shut in high CO2 rate wells and periodically test 4 lateral wells early 2000.
All costs preliminary

FIGURE G.7

wellbywell_with_tract2_slimtube

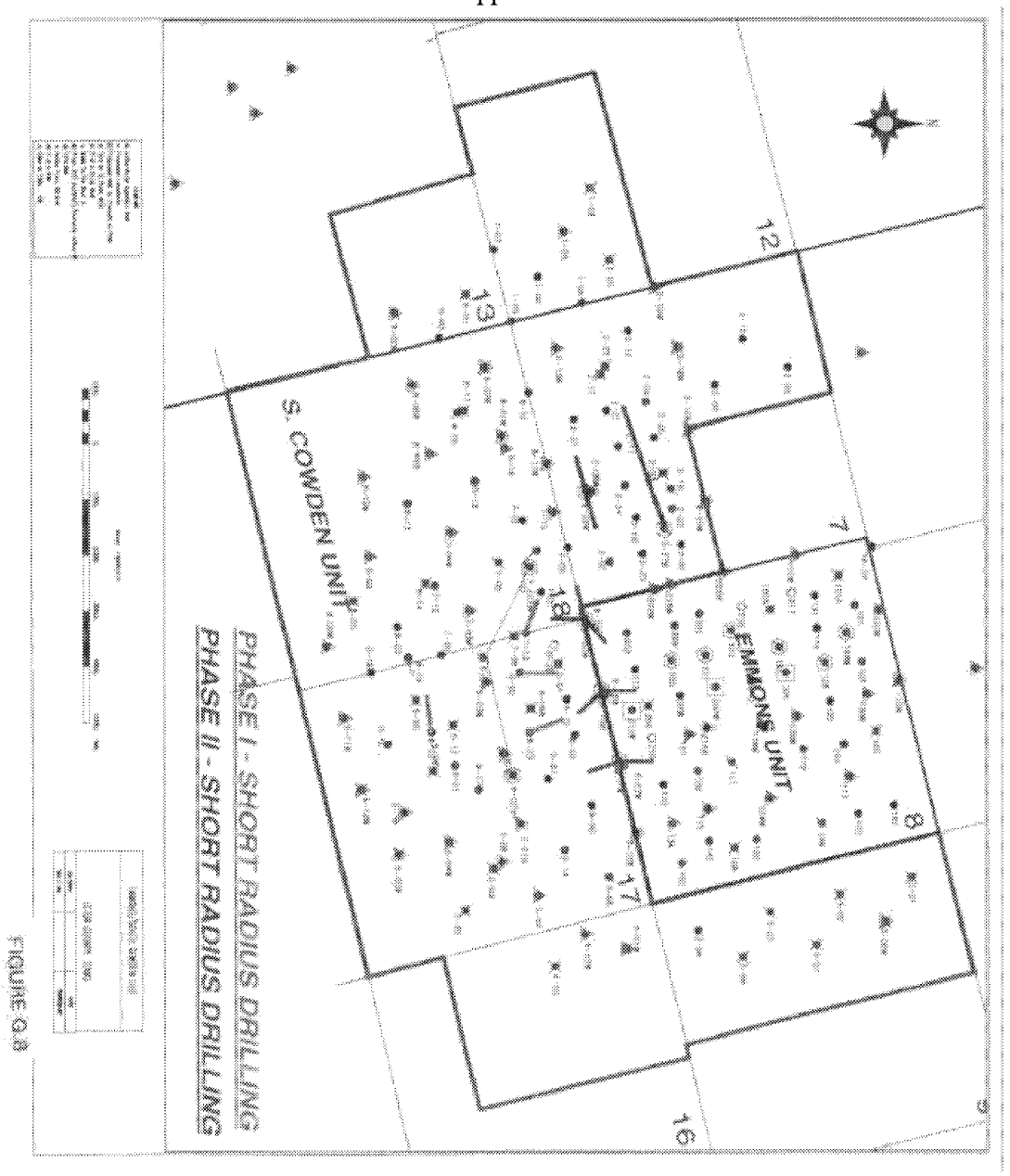

PHASE I - SHORT RADIUS DRILLING
PHASE II - SHORT RADIUS DRILLING
S. COWDEN UNIT
S. EMMONS UNIT
12
13
18
7
8
17
19
6

FIGURE G-8

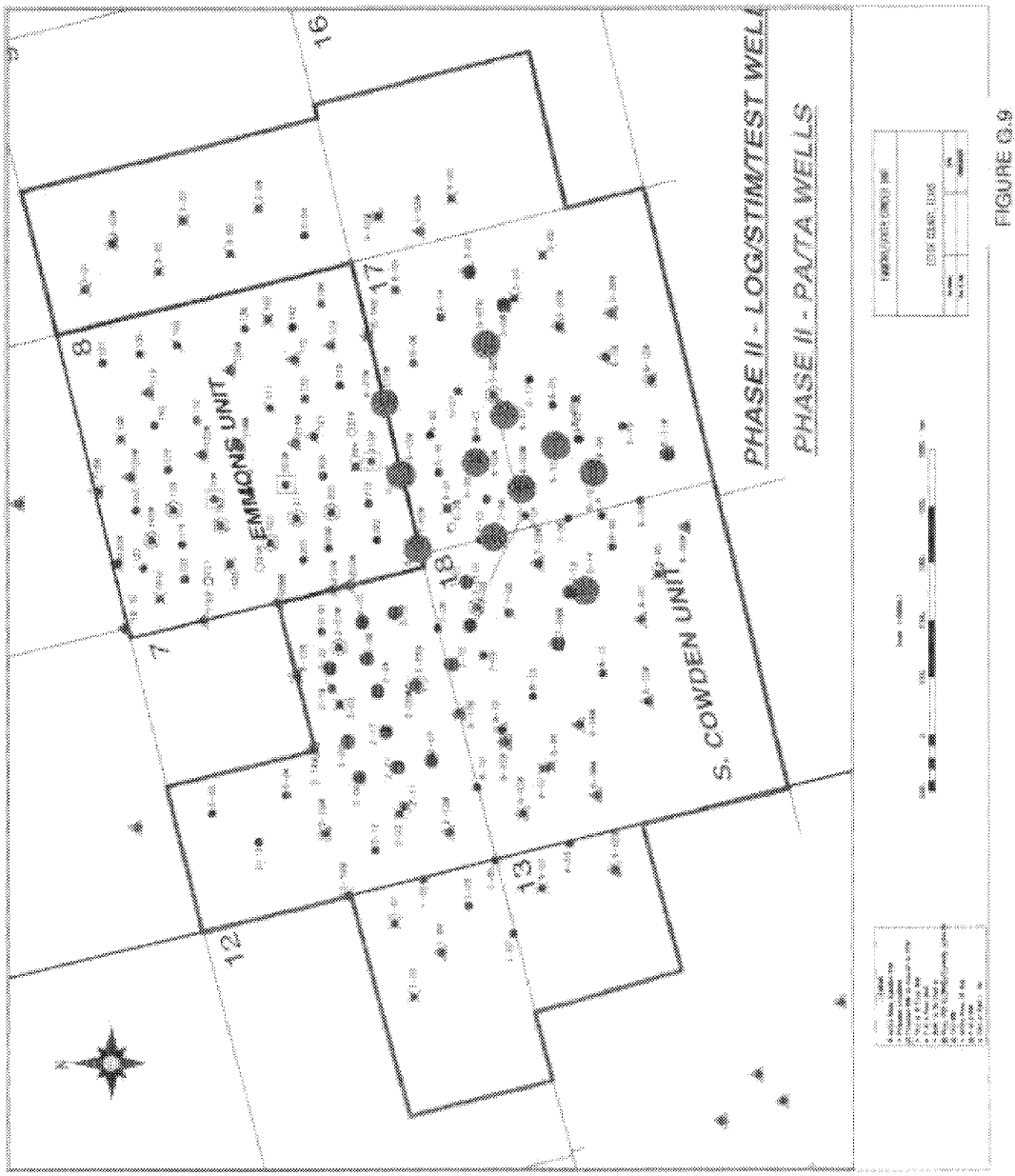

PHASE II - LOG/STIM/TEST WELL
PHASE II - PA/TA WELLS
EMMONS UNIT
S. COWDEN UNIT
16
17
8
7
18
13
12

FIGURE 6.9

SOUTH COWDEN OPTIONS DEC1999

CHALLENGES FOR PHILLIPS

- DEMONSTRATING SHORT RADIUS LATERALS AND STIMTUBE WILL WORK
- FINDING SUITABLE POLYMER/FOAMED CEMENT TO SEAL UP INDUCED FRACTURES
- USING CEMENT CAPABLE OF WITHSTANDING 20 YEARS CO2 PRODUCTION/INJECTION
- METHODS TO CLEAN OUT LATERALS
- IMPROVE SIMULATION FORECASTS USING PRODUCTION HISTORY
- REDUCING OPERATING EXPENSE TO INCREASE FIELD LIFE AND RECOVERY.

FIGURE G.10

SOUTH COWDEN OPTIONS DEC1999

LESSONS LEARNT FROM IMPLEMENTING CO2 FLOOD SINCE START UP IN 1996

- OFFSET WELL PRODUCTIVITY ... NOT ALWAYS THE SAME

- IMPLEMENTING CO2 FLOOD IN CERTAIN LAYERS ....
  ..... MUST BE ABLE TO SELECTIVELY STIMULATE IN THOSE
  LAYERS ..... ECONOMICALLY ... PLUS ENSURE COMMUNICATION
  PATHS SUCH AS POORLY PAd WELLS ARE SEALED

- MATURE WATERFLOODS HAVE INDUCED FRACTURES IN AREAS
  OF HISTORICAL OVERINJECTION ... AVOIDED .. OR .. METHODS TO SEAL UP NEAR WELL AND DRILL AWAY USING LATERALS

- USE OF LATERAL WELLS FROM EXISTING VERTICAL WELL COST EFFECTIVE APPROACH TO IMPROVING PRODUCTIVITY/INJECTIVITY/
  SWEEP/RECOVERY .....MAY OPEN UP AREAS NOT ORIGINALLY
  CONSIDERED AS CO2 FLOODABLE

FIGURE H.1

APPENDIX H

Reports and Technology Transfer

During late 1996, a paper entitled "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO_2 Flood, South Cowden Unit, West Texas," was written and submitted to the Oklahoma Geological Survey (OGS) by Craig D. Caldwell. This paper was previously presented as a poster session at the March 1996, meeting "Platform Carbonates of the Southern Midcontinent" sponsored by the OGS. The OGS is planning on publishing 1000 copies of the proceedings from this meeting.

Kimberly B. Dollens presented a talk entitled "Cost Optimization/Operations in WAG Flooding: E. Vacuum Grayburg and So. Cowden Units," and participated in a panel discussion on "Cost Optimization - Installation and Operations, " at the 2nd Annual Permian Basin CO_2 Conference in Midland, Texas, December 10-12, 1996.

Continued development of a South Cowden Unit Internet site for data and technology transfer was initiated. The prototype (for intra-company use only) was completed, but editing was not finalized for the Internet.

SPE Paper 37470, "The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO_2 WAG Horizontal Injection Wells," written by Kimberly B. Dollens, Burl W. Wylie, James C. Shoumaker, Orjan Johannessen, and Phil Rice, was presented by Ms. Dollens at the 1997 SPE Production Operations Symposium, March 9-11, 1997, in Oklahoma City, Oklahoma. Ms. Dollens also presented this paper at the Phillips Petroleum Company Exploration and Production (E&P) Technical Symposium in Bartlesville, Oklahoma, April 2-4, 1997. The abstract is included as Attachment I.

James C. Shoumaker presented a poster session entitled "Drilling and Completions Considerations of Horizontal CO_2 Injection Wells - South Cowden Unit," at the Phillips Petroleum Company Exploration and Production (E&P) Technical Symposium in Bartlesville, Oklahoma, April 2-4, 1997. The abstract of this poster session is included as Attachment II.

Kimberly B. Dollens presented the project review at the U.S. Department Of Energy, National Petroleum Technology Office, Oil Technology and Gas Environmental Review on June 16, 1997, in Houston Texas.

Kimberly B. Dollens participated as a panelist and presented a paper entitled "Application of Horizontal Injection wells in the South Cowden Unit CO_2 Flood," at the 1997 Society of Petroleum Engineers (SPE) Horizontal Well Conference held in Midland, Texas, September 17 and 18, 1997.

Kimberly B. Dollens participated as a panelist and presenter in the 1997 SPE CO_2 Conference (Dec. 10-11, 1997) in Midland, Texas. The conference focused on actual case histories. The talk was entitled "Application of Horizontal Injection Wells in the South Cowden Unit CO_2 Flood". She also participated as a presenter in the 1998 Permian Basin Recovery Conference in Midland, Texas, on Thursday, March 26, 1998.

Kimberly B. Dollens submitted an abstract for a paper entitled "Field Implementation of a CO_2 Flood in a Small Waterflood-Depleted Carbonate Unit," for presentation at the 1998 Southwestern Petroleum Short Course in Lubbock, Texas, April 8-9, 1997. The proposed paper was co-authored by Ms. Dollens, Ken J. Harpole, and Larry Hallenbeck.

T. F. McCoy, K. J. Harpole, and K. B. Dollens submitted an abstract to the selection committee for the Sixth International Oil and Gas Conference and Exhibition in Beijing, China, on November 2-6, 1998. The abstract entitled "Transient Test Analysis Case History for Two Horizontal Miscible Gas Injection Wells". - This paper was accepted as an alternate paper, but will not be presented or included in proceedings.

Craig Caldwell and Kimberly B. Dollens presented a poster session entitled "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO_2 Flood, South Cowden Unit, West Texas" at the Permian Basin Section of the Society of Economic Paleontologists and Mineralogists' (SEPM) Permian Basin Core Workshop in Midland, Texas, on Thursday, February 26, 1998.

A technical paper entitled Integrated Geological and Engineering Characterization of an Upper Permian Carbonate Reservoir, South Cowden Unit, Ector County, Texas -- A Work in Progress? was presented at the American Association of Petroleum Geologists Midcontinent Section Meeting, in Tulsa, Oklahoma, October 9-10, 1995. The paper was presented by Craig Caldwell, and described the results of the integrated reservoir characterization work, including regional mapping and 3-D seismic interpretation, the development of a stratigraphic framework, log analysis, and core analysis.

Ahmad Moradi made a presentation titled "Laboratory and Field Evaluation of CO_2 Foam" at the Petroleum Recovery Institute Forum on EOR Foam, Calgary, Alberta, Canada, November 15, 1995.

A poster session entitled "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO_2 Flood, South Cowden Unit, West Texas" was presented by C.D. Caldwell at the Oklahoma Geological Society / U.S. Dept. Of Energy Symposium, "Platform Carbonates in the Southern Midcontinent", Oklahoma City, OK, March 26 -27, 1996. A number of core samples were included in the exhibit. This poster session summarized, again, the results of the integrated reservoir characterization study.

The Society of Petroleum Engineers Permian Basin Oil & Gas Recovery Conference held March 27-29, 1996 in Midland, TX, included a poster session entitled "Construction of a 3 -D Geologic Reservoir Description from Core and Well Log Data, South Cowden Field CO_2 Project". A technical paper, SPE 35226, "Use of Production and Well Test Data with Predictive History Matching to Improve Reservoir Characterization for CO_2 Flooding at the South Cowden Unit" by K. J. Harpole, M.G. Gerard, S.C. Snow, and C.D. Caldwell was also presented. This paper presented the approach used in the South Cowden project to improve the delineation of the

porosity and permeability distribution in the reservoir by integrating production performance data with 3-D geological modeling and predictive history matching techniques.

Matthew G. Gerard made a presentation titled "Application of Horizontal CO_2 Injection Wells at South Cowden Unit" to the Midland chapter of the Society of Petroleum Engineers, April 1, 1996. Gerard later made the same presentation at the Permian Basin Horizontal drilling Symposium on May 8, 1996.

Paper SPE 35429, "Determination of Relative Permeability and Trapped Gas Saturation for Predictions of WAG Performance in the South Cowden CO_2 Flood" by D.C. Wegener and K. J. Harpole was presented at the Improved Oil Recovery Symposium in Tulsa, OK on April 22-24, 1996. This paper describes the laboratory experimental apparatus and procedures developed and used to measure key parameters (CO_2 relative permeability, residual oil saturation following miscible CO_2 displacements, trapped gas saturation, and hysteresis effects) governing CO_2 injectivity and displacement efficiency in the South Cowden miscible CO_2 WAG injection project.

Matthew G. Gerard made a presentation of the Phase I work at the DOE Class II Workshop held at the CEED in Midland, Texas on May 15-16, 1996.

Ahmad Moradi, E.L. Johnston, D.R. Zornes and K.J. Harpole submitted an abstract entitled "Laboratory Evaluation of Surfactants for CO_2-Foam Applications at the South Cowden Unit", for the International Symposium on Oilfield Chemistry, February 18-21, 1997 in Houston, Texas. A copy of the abstract is attached. (Attachment IV)

Matthew G. Gerard and Ken J. Harpole submitted an abstract entitled "Incorporating Production and Petrophysical Data to Improve Predictivity History Matching for a CO_2 Flooding Project at South Cowden Unit, West Texas" for the Fourth International Reservoir Characterization Technical Conference, on March 2-4, 1997 in Houston, Texas. A copy of the abstract is attached.

Appendix H

LIST OF ATTACHMENTS

Attachment	Description
I	Abstract submitted entitled "Laboratory Evaluation of Surfactants for CO_2-Foam Applications at South Cowden Unit".
II	Abstract submitted entitled "Incorporation Production and Petrophysical Data to Improve Predictivity History Matching for a CO_2 Flooding Project at South Cowden Unit, West Texas".
III	Abstract submitted entitled "The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO_2 WAG Horizontal Injection Wells".
IV	Abstract submitted entitled "Drilling and Completions Considerations of Horizontal CO_2 Injection Wells - South Cowden Unit".

ATTACHMENT I

LABORATORY EVALUATION OF SURFACTANTS FOR CO_2-FOAM APPLICATIONS AT SOUTH COWDEN UNIT

Ahmad Moradi-Araghi, E. L. Johnson, D. R. Zornes and K. J. Harpole

An extensive laboratory study was conductedto evaluate foaming ability of four surfactants, Chaser "CD-1045, CD-1050, Rhodapex " CD-128 and Foamer NES-25 were tested in South Cowden Unit (SCU) cores. The objective of this study was to identify suitable surfactants to produce stable CO_2-foam for possible application at SCU for mobility control and diversion of CO_2 in horizontal injection wells. This study is part of a Department of Energy (DOE) Class II demonstration project, partly funded by DOE.

Several core tests were performed with foams produced by co-injection of surfactant solutions at various concentrations in a synthetic SCU brine, and CO_2 under about 2000 psi of pressure and 98? F at 20-90% foam quality. All field cores (diameter: 1", length: 46") used in this study were highly inhomogeneous with significantly varying permeability in different sections of the core. A typical core that was equipped with three pressure taps along its length exhibited permeabilities of 10 to 600 md in its four sections. The resistance factors (RF) determined for flowing the foam in each section of the core appeared to vary with the permeability of that section. The foams exhibiting this behavior were referred to as "smart foams" by J. P. Heller. Resistance factors measured for CO_2-foams produced in the same core with the four surfactants under identical conditions showed the best performance equally for Chaser CD-1050 and Rhodapex CD-128, followed by Chaser CD-1045 and Foamer NES-25, which were also comparable. However, Rhodapex CD-128 and Chaser CD-1045 were chosen for further studies based on availability and previous field experience. RF values measured for the foams produced with these surfactants at various concentrations maximized between 50% to 70% foam quality. The maximum, however, shifted tohigher foam qualities with increased surfactant concentration.

The chosen surfactants were secondly evaluated each by coinjection as well as SAG (Surfactant Alternating with Gas) processes to investigate the effect of surfactant concentration and frontal velocity. The resulting foams exhibited a shear thinning behavior with resistance factors increasing with surfactant concentration. The performance of the foams produced by the SAG process with both surfactants in the same core at 70% foam quality diminished with slug size.

Both chosen surfactants evaluated for their CO_2-foam properties in a test core at residual oil saturation produced lower RF values than the tests performed in cores with practically no movable oil to CO_2 flow. These tests which were performed at varying frontal velocities and foam quality, also showed the shear-thinning property and dependency of RF values on foam quality. This data coupled with adsorption tests being carried out presently in our laboratory, should help in selecting Rhodapex " CD-128 or Chaser" CD-1045 as candidate surfactant.

Appendix H

ATTACHMENT II

INCORPORATING PRODUCTION AND PETROPHYSICAL DATA TO IMPROVE PREDICTIVE HISTORY MATCHING FOR A CO_2 FLOODING PROJECT AT SOUTH COWDEN UNIT, WEST TEXAS

Matthew G. Gerard and Ken J. Harpole, Phillips Petroleum Company

The South Cowden Unit is one of three mid-term demonstration projects being conducted under the DOE Class II Oil Program for shallow-shelf carbonate reservoirs. The South Cowden project is designed to demonstrate the technical and economic viability of horizontal CO_2 injectors to improve CO_2 project economics for small fields approaching abandonment.

Extremely heterogeneous permeability distributions make it difficult to match individual well performance in simulations of carbonate reservoirs. Yet individual well performance matching can be critical if the simulation model is to be used to optimize injection and production well placement in a CO_2 flood development plan. Detailed petrologic study of core often provides the best information on reservoir flow properties, but cores are rarely available in sufficient quantity to map permeability and porosity variations throughout an entire field. In South Cowden field, variations in permeability within the dominant rock-type are too complex to be represented by a single permeability-porosity transform. This project saw an improvement in the reservoir description by integrating information from individual well production histories with the core and well log data.

Core data established a relationship between permeability and total fluid producing rate. Total fluid producing rate was mapped across the field, and used to compute permeability from the well log porosity. A 3-D model of permeability and porosity was interporated from the well log data, which was then used to construct the reservoir simulation model. This approach resulted in a marked improvement in individual well matches of oil and water production rates. The simulation model was used with greater confidence to quantify CO_2 flood performance for a number of development schemes.

ATTACHMENT III

TITLE: THE EVALUATION OF TWO DIFFERENT METHODS OF OBTAINING INJECTION PROFILES IN CO_2 WAG HORIZONTAL INJECTION WELLS

AUTHORS: Kimberly B. Dollens, James C. Sloumaker, Burl W. Wylie, Phil Rice, and Orjan Johannessen

Two different methodologies were employed in obtaining injection profile surveys in two CO_2 water-alternating gas (WAG) horizontal injection wells in the South Cowden Unit (SCU) CO_2 project. Both methods were used once during an initial water injection period to establish a baseline profile. Then, the first method was utilized on both of the horizontal injection wells during a CO_2 injection period. The first method utilized a coiled tubing conveyed, memory-based logging system, including a correlation gamma ray and collar locator log; injection and shut-in temperature, capacitance, flowmeter and pressure gradient; and interface tag. The second method utilized a logging and injection program wherein coiled tubing and wireline were run in the injection well with a Y-block and coiled tubing side-entry assembly attached to the coiled tubing below the spot valve. The tool consisted of a positive and negative gamma ray and temperature tool, and utilized a slug of more than one gallon of radioactive gel rather than the standard injection volume of approximately 50 cc or 1 cc per station. Actual field results are reviewed, and the two methodologies discussed for application in CO_2 WAG horizontal injection systems.

Appendix H

ATTACHMENT IV

TITLE: DRILLING & COMPLETION CONSIDERATIONS OF HORIZONTAL CO_2 INJECTION WELLS- SOUTH COWDEN UNIT

AUTHORS: James Shoumaker and Sam Hyden

The South Cowden Unit 6C25H and 7C11H were drilled as horizontal CO_2 injection wells. The horizontal wells were an essential component of the economic viability of the tertiary recovery project. The CO_2 water-alternating-gas (WAG) injection well trajectories were designed to optimize reservoir performance. The trajectories of the 6C25**H** an 7C11H were drilled with a 12 degree/110 foot build-up rate, 6-1/8" openhole lateral lengths -1 1935' (Azimuth: 76 degrees East of True North) and 1337' (Azimuth: 65 degrees West of True North), respectively. The wells were designed mechanically to optimize well injection performance and maximize duration of their utility due to the required CO_2 service. Both wells were equipped with 9-5/8", 36 ppf, J-55 surface casing; 7", 20 ppf, J-55 production casing through the curve; and injection packer/tubing/wellhead designed for CO_2 service. The wells were stimulated with 15% HCL acid by coiled tubing acid washing sweeps. Current injection is approximately 3.5 MMscfd of CO_2 per well, which is essentially a three fold increase in injectivity of a single vertical injection well in the same field. This presentation will review the planning, designing, and techniques utilized to meet the South Cowden Unit horizontal CO_2 injection well drilling/completion project.

APPENDIX I

CO2 Horizontal Well Test Analysis

Appendix I

Summary

Wells 7C11H and 6C25H were tested with downhole pressure gauges in February and May 2000. The first tests took place as the wells were shut in to allow cessation of carbon dioxide (CO_2) injection for lateral drilling. The second tests took place as the wells started injecting again in early May 2000. The first tests were simple fall off tests; the second tests were multirate injection tests followed by a fall off.

The analysis has proven extremely useful for understanding the characteristics of both wells. In particular the test on well 7C11H has revealed that the fracture present at the wells' toe is confirmed as a pressure induced fracture that currently appears to be getting easier to inject into when compared to CO_2 start up in 1995.

The fracture dimensions at 7C11H are dependent on the thickness used for analysis, but can be estimated as:

Xf (half length) = 32 feet ('), using an infinite conductivity model and 280' thickness.
Xf (half length) = 70 feet, using an infinite conductivity model and 60'thickness.
The closure pressure is estimated at 1988 pounds per square inch gauged (psig).

These results could be used for potential volumes required for conformance work.

Also of note is well 6-05 injectivity compared to 7C11H. Even though 7C11H appears to be in contact with an infinite conductivity fracture it appears to have a much lower injectivity index (at low rates). Well 7C11H average is 9.9 MSCF/D/psi compared to 6C25H with 45 MSCF/D/psi. Which suggests if the conformance is resolved at 7C11H, a horizontal well would have improved injectivity in the area around wells 7-01/ 7-13.

Well 6C25H analysis suggests either vertical communication is larger than currently modelled or the distance is less to the impermeable boundary, above the horizontal well. Therefore there maybe sections that have rapid vertical communication capabilities (such as a karsted infill area, or highly burrowed sections), or the top of the E zone maybe acting as a permeability barrier.

CO_2 Properties

A sample of the re-combined CO_2 stream was taken at injection well 2-26. The compositional analysis was given to Ken Harpole in Bartlesville who then generated the PVT properties for the analysis.

Wells 6C25H and 7C11H have both been injecting CO_2 continuously since 1995 so it is likely the region surrounding both wells are dominated by CO_2 properties.

7C11H February Test

Appendix I

The diagnostic plot reveals a system that appears to be related to a negative skin of some form. The initial storage is followed by a linear flow type system, followed by a fairly well defined radial flow section from which average reservoir properties can be determined. Refer to Figure 1. This type of behaviour could be characteristic of a single fracture system (with infinite/finite conductivity) or a horizontal well with early vertical radial flow masked by storage period.

Of note for this test are higher pressures encountered, with initial injection pressures at 2200 psig which falls off to 2180 psig at the end of the test. The extrapolated pressure P* is predicted to be approximately 2020 psig

If the system is related to a fracture then the full San Andres thickness could be in communication with the fracture, an effective thickness of up to 280'. The offset 7 -10 well provides a good description of the San Andres interval in this area. Core permeabilities vary by layer, highest in the lowest A zone and lowest in the G zone (refer to attached Figure 2). Typically the "p50" values of permeability are less than 1 md, with the exceptions of the E zone at 4.5 mD and the A zone at 11 mD.

The analysis of the late radial flow, using a homogeneous radial flow model, suggest a K*H=84mD-ft. If the thickness used is the entire 280' interval, this is an average K=0.3mD and effective skin=-4. If a thickness of 60'is used (corresponding to the E zone thickness), average K=1.4mD and Skin = -5, refer to Figure 3.

As discussed, various negative effective skin models fit the fall off data. Figure 4 illustrates finite/infinite conductivity fracture model and horizontal well model matches. All models give reasonable matches to both the diagnostic log-log plot and the real-time linear data. Note the horizontal well model was easier to match using a thickness of 60'as opposed to the full 260'.

7C11H May Test

After the well had been shut in for approximately 3 months a multirate test and 24 hour fall off took place. The diagnostic plot shows slightly different character, with a less defined½ slope followed by no late time radial flow behaviour. Refer to Figure 5. Also of note is a totally different late time behaviour starting at approximately 17 hours of fall off. At this point the derivative takes a dramatic dip downward.

Of note for this test is lower pressures encountered, when compared to the February test, with initial injection pressures at 2090 psig, which falls off to 1986 psig at the end of the test. The extrapolated pressure P* is predicted to be approximately 1954 psig.

Also of note on the semi-log and linear flow plot ($t^{½}$) is the dramatic change in behaviour on both plots, which corresponds to the change in derivative on the diagnostic at 17 hours. Initially this was interpreted as gauge error, because of the completely different behaviour to the February fall of diagnostic. After checking with the gauge company and reviewing the back up gauge performance it became apparent that this was a true pressure behaviour as both gauges track each other during the fall off, Figure 6.

If this is a true response it cannot be caused by a reservoir effect such is increasing transmissibility. Such a dramatic effect can only be caused by a fracture closing at the closure pressure. A typical closure pressure determination from a pump in test is illustrated in Figure 7, which draws a very direct analogy with the linear flow plot ($t^{½}$) presented in Figure 5.

7C11H Fracture Closure Pressure

Results from the February test do not reveal any form of fracture closure, yet the May test reveals a closure pressure of 1988 psig. The February test can therefore be assumed to take place above the fracture pressure, and the properties derived from the diagnostic plot reveal fracture characteristics as opposed to those of a horizontal well.

Also of note is a comparison of 7C11H fracture pressure encountered with these, more recent, tests and pump in tests performed in August 1996 using water, Figure 8. This illustrated a fracture initiation pressure of 2570 psig at an injection rate of around 450 barrels of water per day (bw/d) and surface injection pressure of 565 psig.

Fracture pressures have therefore reduced considerably since August 1996, suggesting the volumes injected since CO_2 start up have made the fracture easier to pump into by lowering the initiation pressure for fracture formation at the toe of the well.

Also of note from the analysis is the observation that the fracture is *induced* above a certain pressure. This was observed both in 1996 and 2000 testing. This suggests that a *pre-existing* fracture system does not exist at the toe, and is only *induced* to form above a certain pressure.

7C11H Static Gradients/Injectivity/Reservoir Pressure

An injection gradient survey run prior to the February shut in (refer to Figure 9), suggested an average gradient of 0.303 psi/ft, 984-psig surface injection pressure and 2264 psig at a depth of 4420 ft (nipple depth). The static survey run after 6 days of fall off remained at an average 0.306 psi/ft gradient, surface pressure at 892 psig and downhole pressure 2181 psi at 4420 ft. Both surveys therefore suggested no CO_2 gas phase being present.

The gradient run prior to injection start up in May suggested an average 0.267-psi/ft gradient, due to a gas phase at the top 400'. The presence of the gas phase appears to h ave given rise to multiphase effects seen on the surface pressure gauges when the multipoint test was performed, Figure 10. The downhole pressure however gives the expected increasing pressure as rate increases.

A plot of injection pressure against rate, Figure 11, reveals a fairly well defined injectivity index of 9.85 MSCF/D/psi for the multipoint data (note surface injection pressures used were extrapolated from downhole pressure using a gradient of 0.303 psi/ft). Since injection start up injection rate had been held steady at 3 MMSCF/D. Figure 12 illustrates injection rates and pressures from May 24 to June 5. Injection pressures at surface have risen steadily, corresponding to a raise in reservoir pressure around 7C11H, at a rate of 4.8 psi/day until end of May and 1.1 psi/day in June.

Steady downhole pressure at the end of the multipoint test was measured at 1986 psig. Extrapolated pressure for the same fall off data was 1983 psig. Prior to starting the multipoint test, after the well was shut in for 2 months, the measured downhole pressure was 1977 psig (Figure 5g). This indicated a steady decline in pressure around 7C11H at a rate of 3 psi/day, giving some indication that the withdrawal from the 7-01 and the newly drilled lateral at 7-13 were steadily reducing reservoir pressure. At the end of the fall off in February, measured downhole pressure was 2182 psig, extrapolated pressure 2020 psig.

6-Feb Test

As with 7C11H, the diagnostic plot reveals a system that appears to be related to a negative skin of some form. The initial storage is followed by a linear flow type system. No late radial flow section is evident. Refer to Figure 13. This type of behaviour could be characteristic of a single fracture system or a horizontal well with early vertical radal flow masked by storage period and no late radial flow evident.

The offset 6-23 well provides a good description of the San Andres interval in this area. Core permeabilities vary by layer. Typically in the E zone permeabilities are between 1 and 10 mD, Figure 14.

The simplest model of homogenous reservoir and a vertical well with negative skin reveals an effective KH of 103 mD-ft and effective skin of –5.7, Figure 15. An effective thickness of 90' gives an effective perm of 1.1 mD.

It is more likely showing horizontal well character, as previous logging (unlike well 7C11H) suggested no fracturing in this well. No late radial flow is evident so determination of effective KH is uncertain to some degree. The simulation matches using a homogeneous reservoir with horizontal well model, suggest a KH=44 to 56 md-ft. If the thickness used is 90'interval, this is an average K=0.5mD. If a thickness of 65'is used, average K=0.9mD, refer to Figure 16. Both models give reasonable matches to the data, but is maybe more appropriate to use a 90'interval, as core permeability from the offset 6-23 well suggest low permeability barriers may act as flow barriers.

Using a thickness of 90'suggests an effective horizontal well length of 663'(compared to 1850 ft drilled and 1600'logged as injecting in 1996). This may suggest not all the well length is taking CO_2. However, note the falloff test in 1996 in 6C25H suggested only 252'of effective length, when 1600'was logged as injecting.

Also of note are the large effective K_v/K_h ratios required to match the data. If 90'is used as effective thickness a ratio of 11 is needed. Most core data measured in the field suggests an average ratio of unity.

This would suggest either the effective thickness of the formation used foranalysis needs to be much less than 90', or other forms of reservoir vertical communication, not evident in core data, such as burrowing or localized areas of karsting infilled with high porosity systems, have dramatically improved vertical permeability.

6C25H May Test

After the well had been shut in for approximately 3 months a multirate test and 24 hour fall off took place. The diagnostic plot shows slightly different character, with later time behaviour deviating from the previous February diagnostic plot. Refer to Figure 17. Of note is a totally different late time behaviour starting at approximately 17 hours of fall off. At this point the derivative takes an upward trend.

Figure 18 illustrates the diagnostic match for a reservoir and horizontal well with similar properties used to match the February diagnostic. As can be seen, the model used to match the February data does not match the late time behaviour in May.

Between February and May four laterals were drilled at wells 7-13, 6-03, 6-20 and 6-22. The immediate offset wells 6-20 and 6-23 are to the north of 6C25H, approximately 400 to 500 feet. Typically 6-20 produced 50 barrels of fluid per day (bf/d) as a vertical well, 6-23 produced 80 bf/d. Since completion as laterals in April rates are averaging 325 bf/d in each, a 5-fold increase in withdrawal.

The trending of the derivative upward could therefore be interpreted as a boundary effect. The boundary, being the drainage boundary of the wells to the north, is reducing the boundary pressure between wells 6C25H and 6-20/6-23.

Appendix I

6C25H Static Gradients/Injectivity/Reservoir Pressure

An injection gradient survey run prior to the February shut in (refer to Figure 19), suggested an average gradient of 0.320 psi/ft. 1042 psig surface injection pressure and 2382 psig at a depth of 4197 ft (nipple depth). The static survey run after 6 days of fall off remained at an average 0.320 psi/ft gradient. Surface pressure at 963 psig and downhole pressure 2305 psi at 4197 ft. Both surveys therefore suggested no CO_2 gas phase being present.

The gradient run prior to injection start up in May suggested a slightly lighter fluid toward surface with an average 0.303 psi/ft gradient for the well.

As with 7C11H, the surface pressures recorded for 6C25H multipoint test, Figure 20, do not give increase in injection pressure for increased rate. The downhole pressure however gives the expected increasing pressure as rate increases.

A plot of injection pressure against rate, Figure 21, reveals a fairly well defined injectivity index of 45 MSCF/D/psi for the multipoint data (note surface injection pressures used were extrapolated from downhole pressure using a gradient of 0.320 psi/ft). Since injection start up injection rate had been held steady at 3 MMSCF/D. Figure 22 illustrates injection rates and pressures from May 24 to June 5. Injection pressures at surface have risen steadily, corresponding to a raise in reservoir pressure around 6-25, at a rate of 5.66 psi/day.

Steady downhole pressure at the end of the multipoint test was measured at 2182 psig. Prior to starting the multipoint test, after the well was shut in for 2 months, the measured downhole pressure was 2162 psig, Figure 17g. This indicated a steady decline in pressure around -25 at a rate of 2 psi/day, giving some indication that the withdrawal from 6-20/6-23 newly drilled laterals where steadily reducing reservoir pressure. At the end of the fall off in February, after 120 hours of shut in, measured downhole pressure was 2305 psig.

Appendix I

711feb2000_mayinterp : Main Results

Company
Field
Well
Test

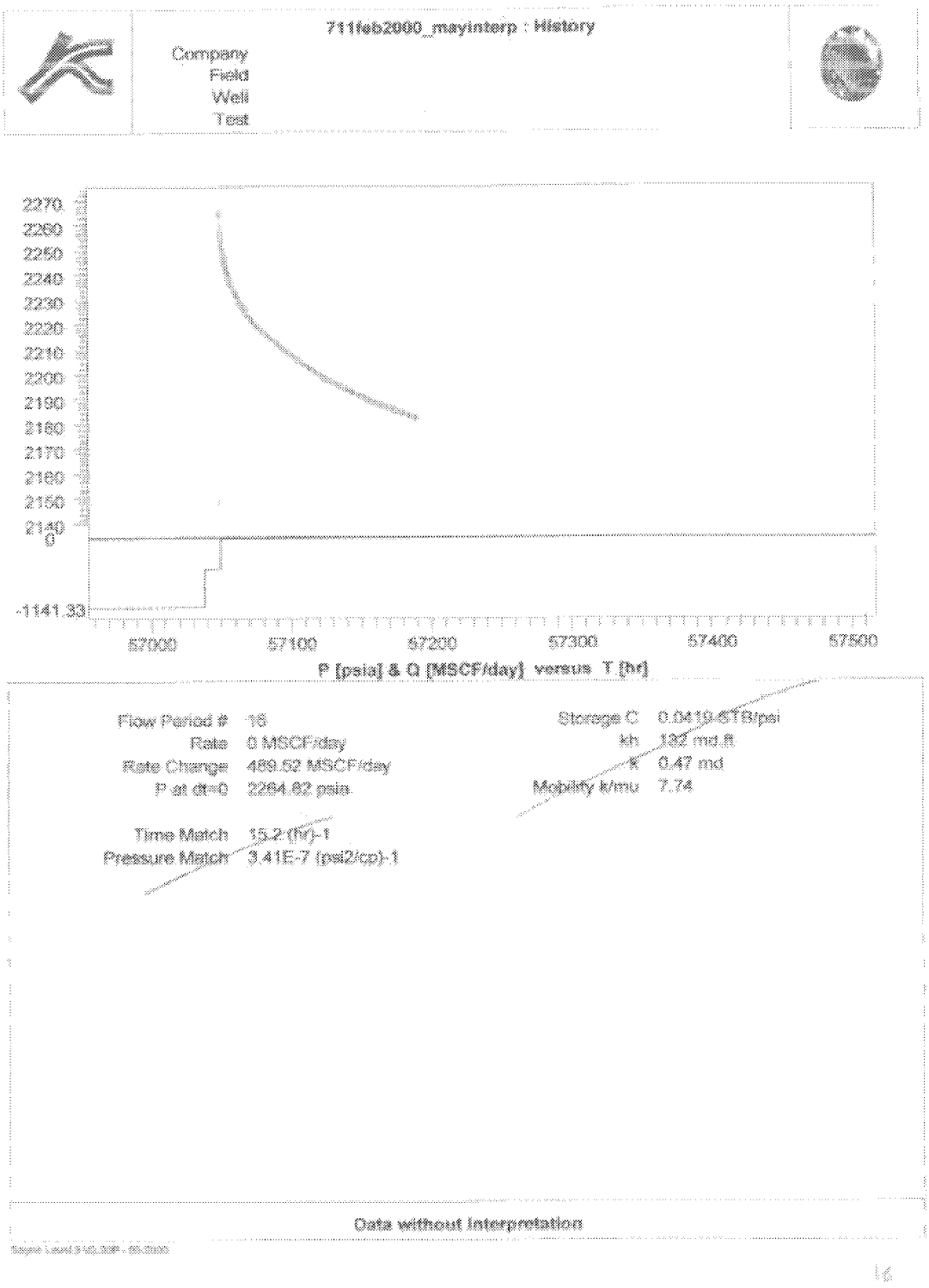
Date
Gauge
Depth
Formation interval
Perforated interval

TEST TYPE	Standard	FLUID TYPE	Gas
Porosity Phi (%)	12	Gas Gravity	0.7
Well Radius rw	0.255 ft		
Pay Zone h	280 ft	Reservoir T	96 °F
		Reservoir P	2018 psia
		Properties	@ Reservoir T&P
		Total Compr. ct	0.000202742 psi-1
		Viscosity	0.0608325 cp

Data without Interpretation

Saphir Level 3 V2.30P - 05-2000

FIG 1A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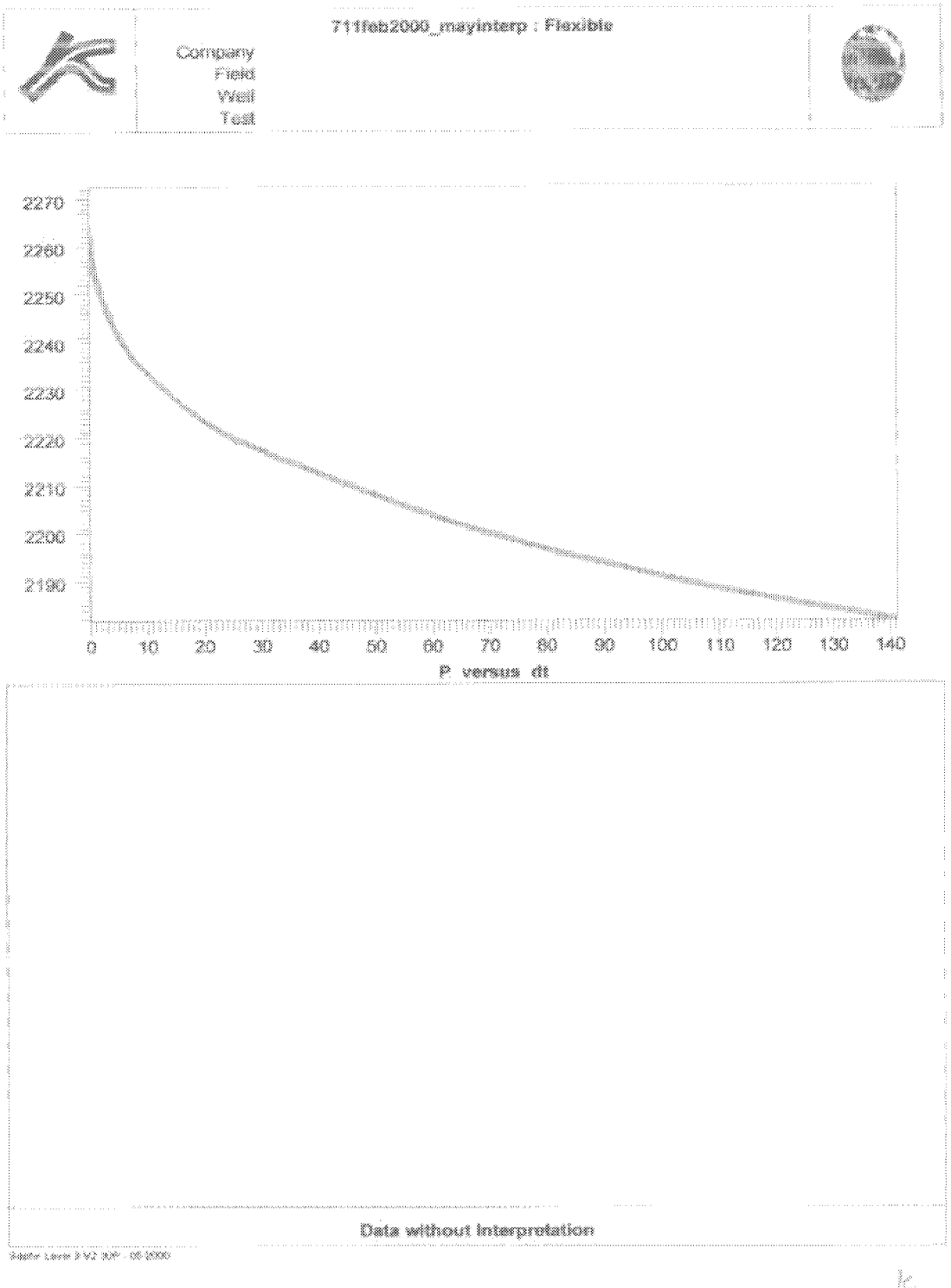
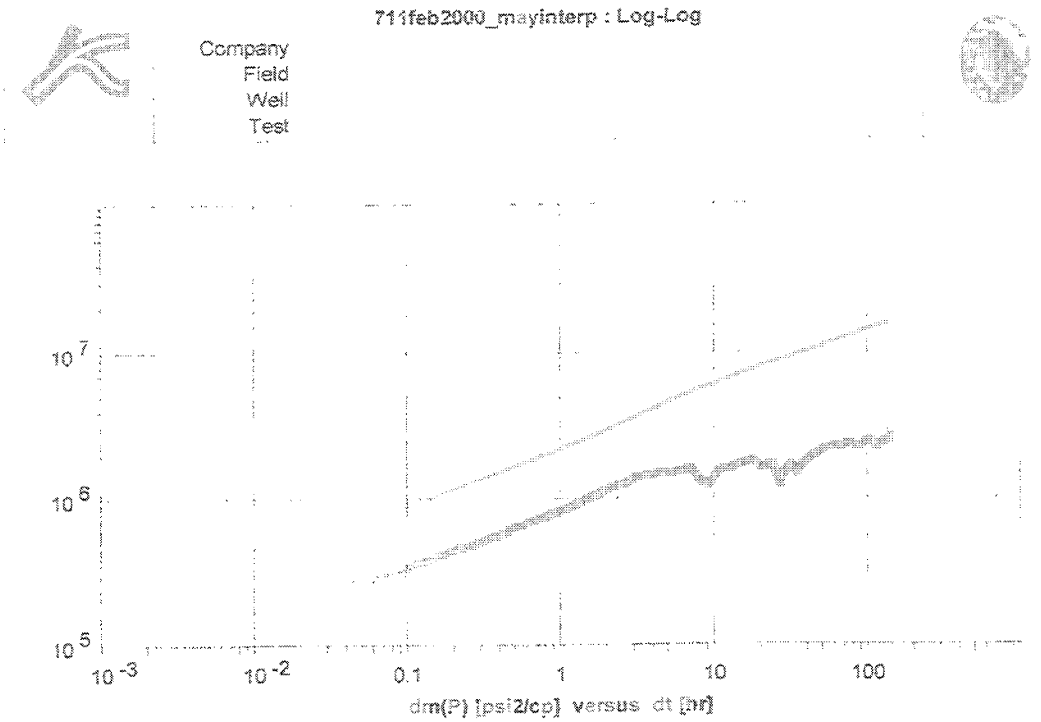
Company
Field
Well
Test
2270
2260
2250
2240
2230
2220
2210
2200
2190
2180
2170
2160
2150
2140
0
-1141.33
57000
57100
57200
57300
57400
57500
P [psia] & Q [MSCF/day] versus T [hr]
Flow Period # 16
Rate 0 MSCF/day
Rate Change 489.62 MSCF/day
P at dt=0 2284.82 psia
Time Match 15.2 (hr)-1
Pressure Match 3.41E-7 (psi2/cp)-1
Storage C 0.0419 STB/psi
kh 132 md.ft
k 0.47 md
Mobility k/mu 7.74
Data without interpretation

Appendix I

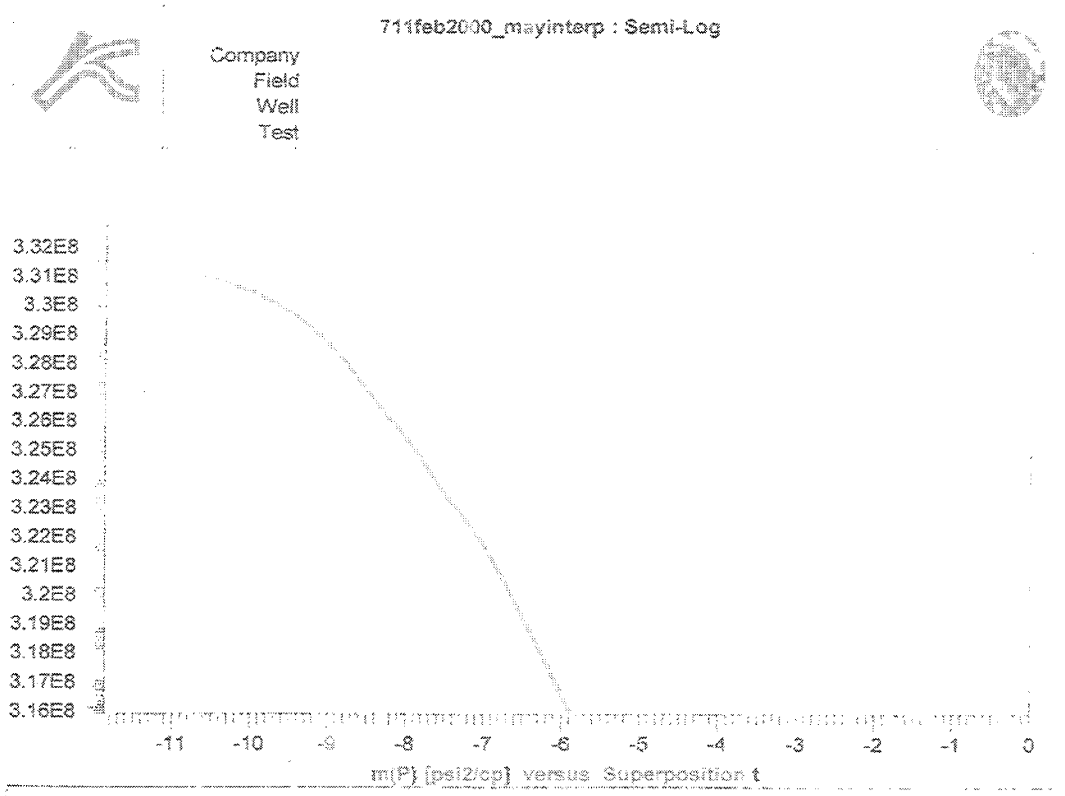

711feb2000_mayinterp : Flexible
Company
Field
Well
Test
2270
2260
2250
2240
2230
2220
2210
2200
2190
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
P versus dt
Data without Interpretation

Appendix I



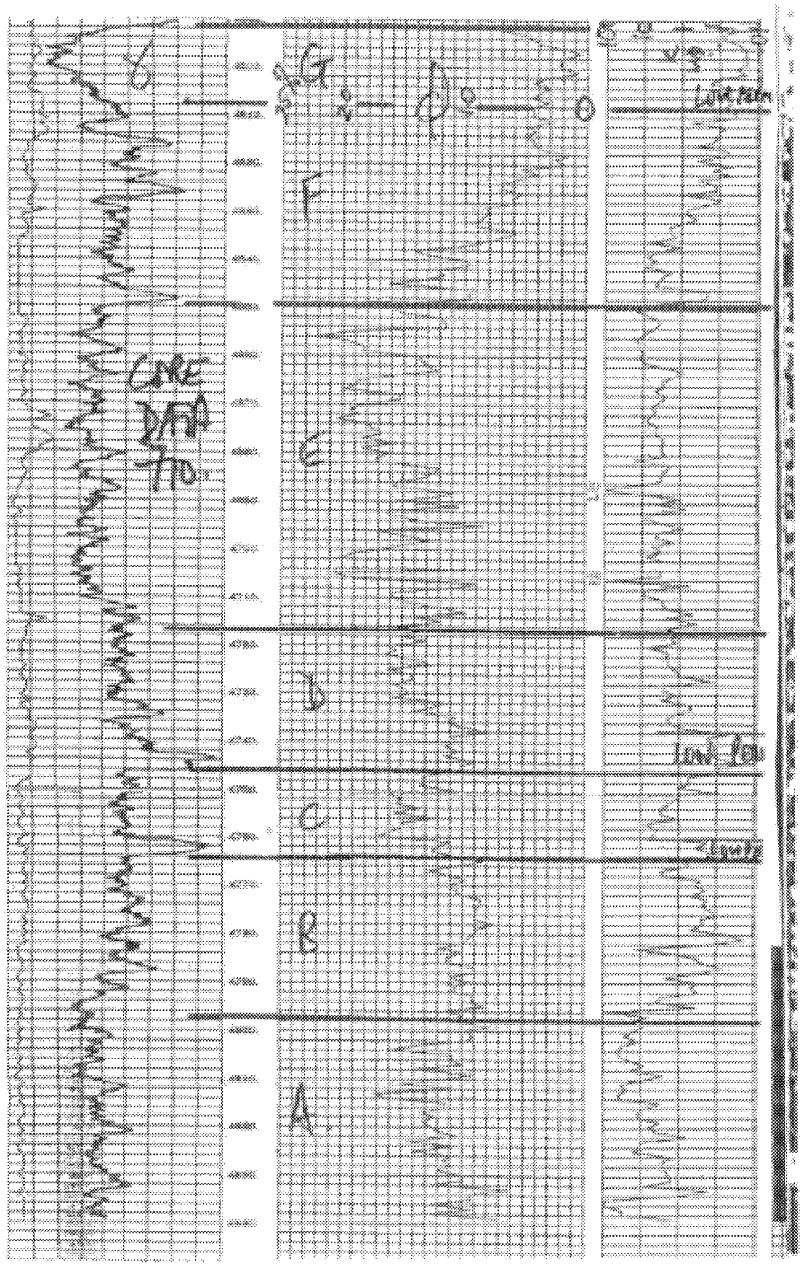
Data without interpretation

Saphir Level 2 V2.30F - 05-2000



Data without interpretation

Appendix I



Appendix I

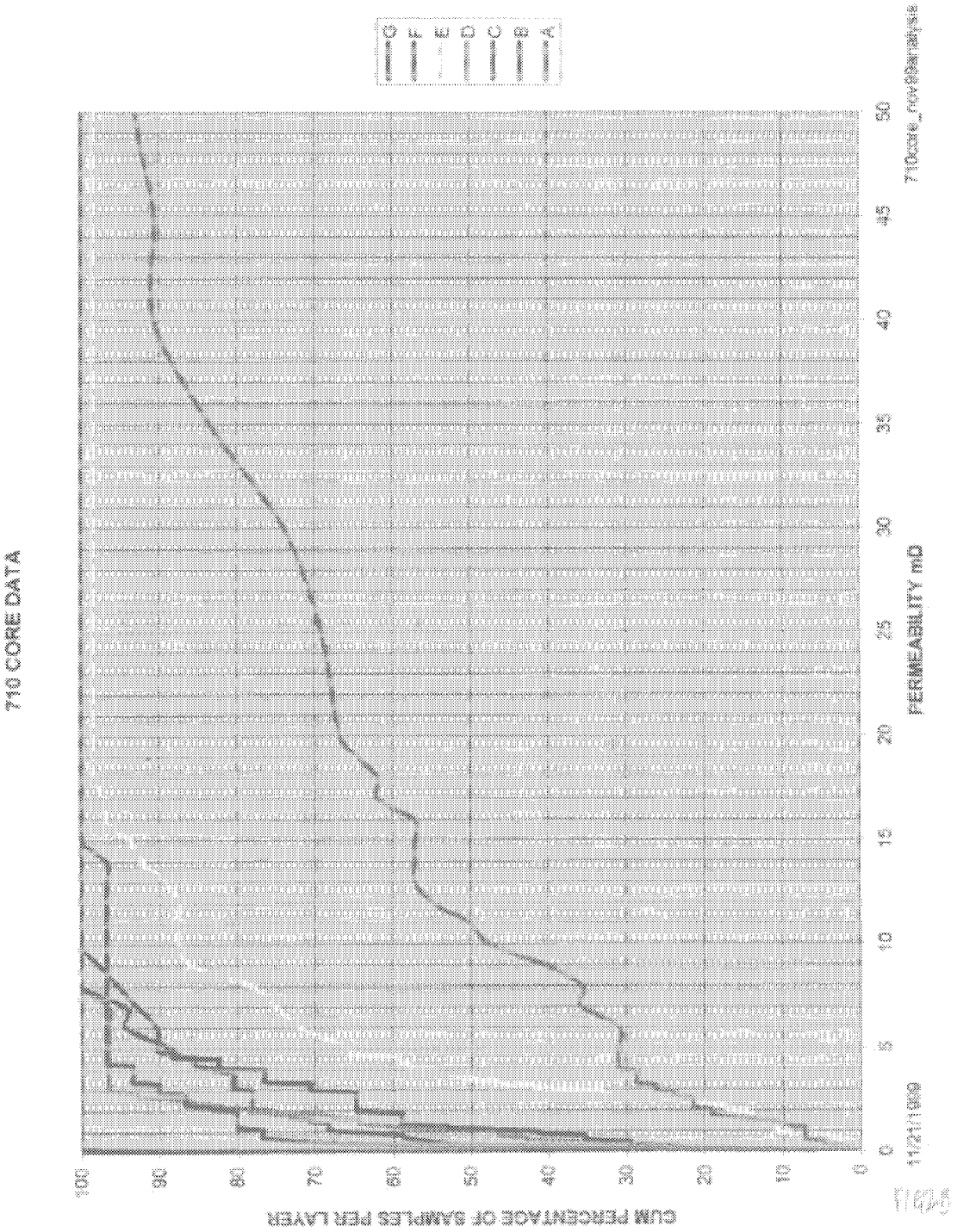
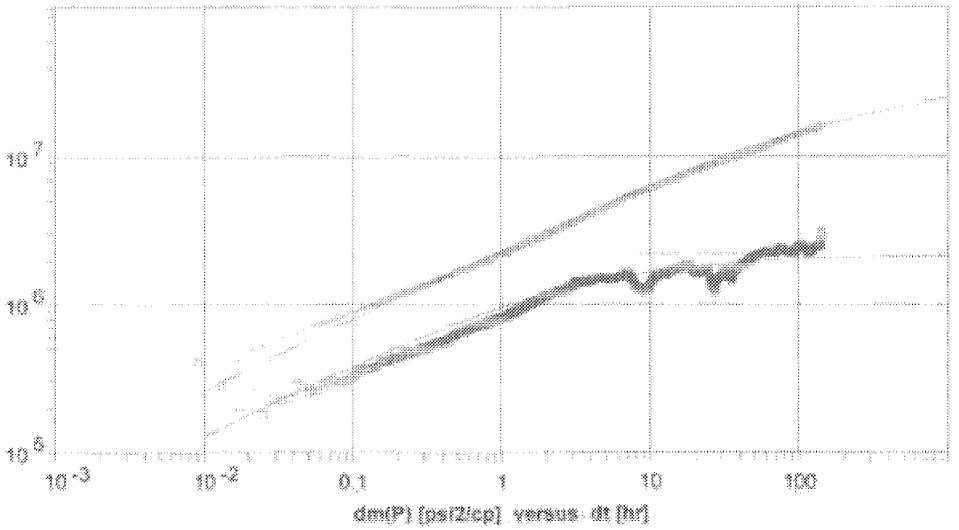


FIG 5

Appendix I

711feb2000_mayinterp : Log-Log

Company
Field
Well
Test



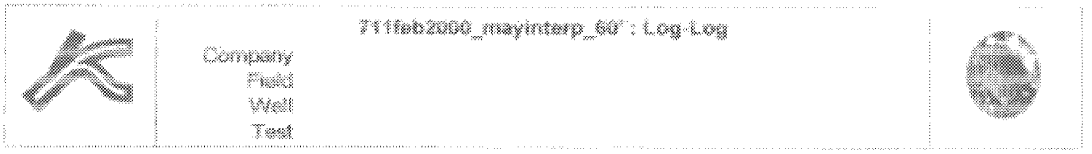
Flow Period #	16	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	489.52 MSCF/day	WELL	Storage & Skin
P at dt=0	2264.82 psia	Storage C	5E-7 STB/psi
Smoothing	0.1	Skin factor	-4
Pi	2034.49 psia	Delta P Skin	-87.5352 psia
Time Match	881000 (hr)-1	kh	90.5 md.ft
Pressure Match	2.35E-7 (psi2/cp)-1	k	0.32 md
		Mobility k/mu	5.33
		Investig. R	161 ft
		Tested Volume	489473 Barrels

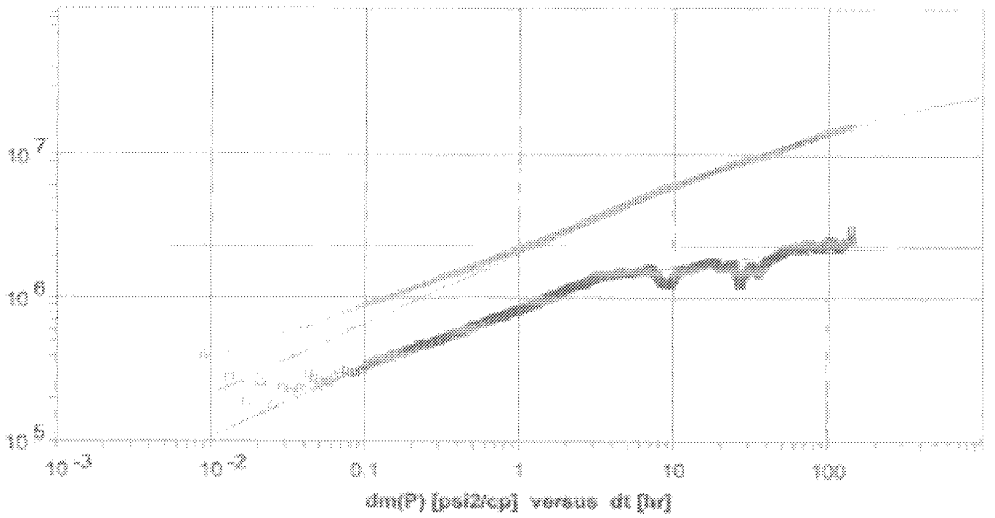
Using SAN ANDRES full 280' Thickness

Saphir Level 3 V2.30P 03-2000

FIG 3A

Appendix I

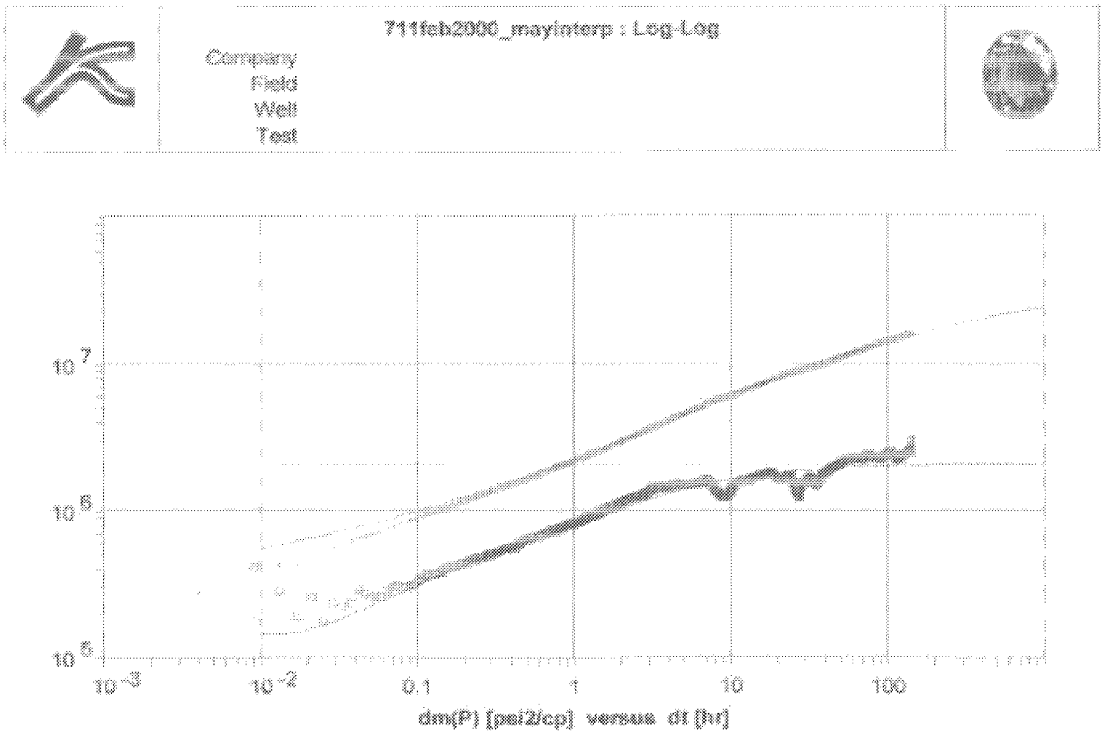




Flow Period #	16	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	489.62 MSCF/day	WELL	Storage & Skin
P at dt=0	2264.62 psia	Storage C	0.00419 STB/psi
Smoothing	0.1	Skin factor	-5
Pi	2025.62 psia	Delta P Skin	-117.697 psia
Time Match	97.7 (hr)-1	kh	84.4 md.ft
Pressure Match	2.18E-7 (psi2/cp)-1	k	1.41 md
		Mobility k/mu	23.1
		Investig. R	336 ft
		Tested Volume	454972 Barrels

Using 60' SAN ANDRES Thickness

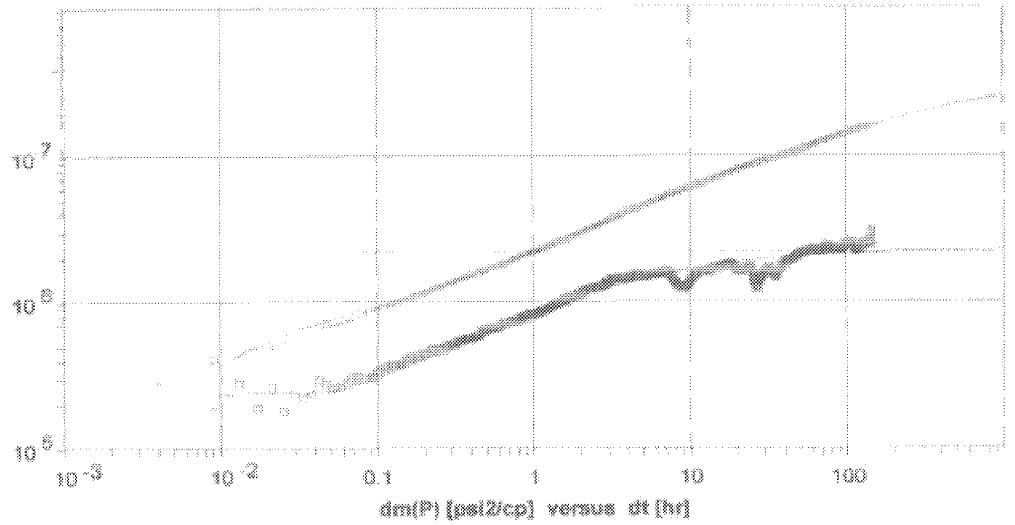
Appendix I



Flow Period #	16	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	489.62 MSCF/day	WELL	Frac. Infinite cond.
P at dt=0	2264.82 psia	Storage C	0.01 STB/psi
Smoothing	0.1	Xf (½ length)	31.3 ft
Pi	2041.98 psia	Skin	0.1
Time Match	46 (hr)-1	kh	94.8 md.ft
Pressure Match	2.45E-7 (psi2/cp)-1	k	0.34 md
		Mobility k/mu	5.56
		Investig. R	165 ft
		Tested Volume	510628 Barrels

Inf Cond Fracture Model

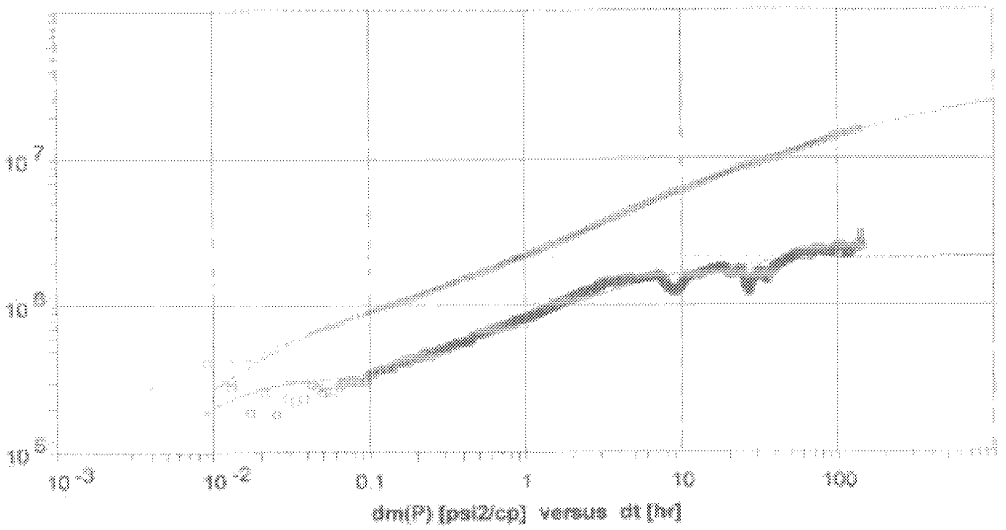
Appendix I



Flow Period #	16	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	489.62 MSCF/day	WELL	Frac. finite cond.
P at dt=0	2264.82 psia	Storage C	0.032 STB/psi
Smoothing	0.1	Xf (½ length)	34.3 ft
Pi	2029.74 psia	fc	1900 md.ft
		fcD	181
Time Match	13.4 (hr)-1	Skin	0.1
Pressure Match	2.29E-7 (psi2/cp)-1		
		kh	68.5 md.ft
		k	0.32 md
		Mobility k/mu	5.19
		Investig. R	150 ft
		Tested Volume	476687 Barrels

Fin Cond Fracture Model

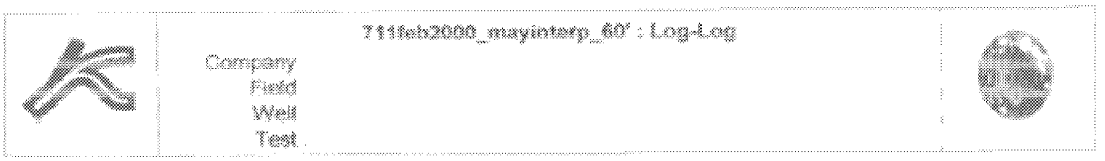
Appendix I

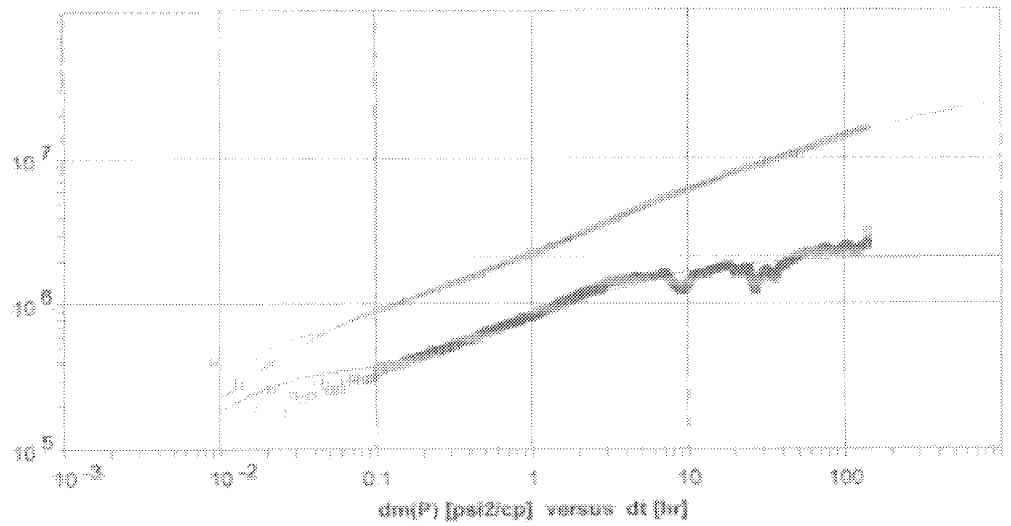


Flow Period #	16	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	489.52 MSCF/day	WELL	Horizontal well
P at dt=0	2264.82 psia	Storage C	0.0471 STB/psi
Smoothing	0.1	Skin factor	-0.15
Pi	2037.45 psia	Delta P Skin	-3.21091 psia
		h	60 ft
Time Match	9.51 (hr)-1	hw	143 ft
Pressure Match	2.38E-7 (psi2/cp)-1	zw	25 ft
		kr.h	92.3 md.ft
		kr	1.54 md
		kz/kr	33.4
		kz	51.4 md
		Top	sealing
		Bottom	sealing
		Mobility kr/mu	25.3
		Investig. R	351 ft
		Tested Volume	467202 Barrels

Horizontal well model with h=60'

Appendix I





Flow Period #	16	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	489.52 MSCF/day	WELL	Frac, infinite cond.
P at dt=0	2264.82 psia	Storage C	0.0705 STB/psi
Smoothing	0.1	Xf (½ length)	69.5 ft
Pi	2040.81 psia	Skin	0.13
Time Match	6.49 (hr)-1	kh	94.2 md.ft
Pressure Match	2.43E-7 (psi2/cp)-1	k	1.57 md
		Mobility k/mu	25.6
		Investig. R	355 ft
		Tested Volume	507684 Barrels

Infinite Conductivity well model with h=60'

fig 4.2

711may2000 : Main Results

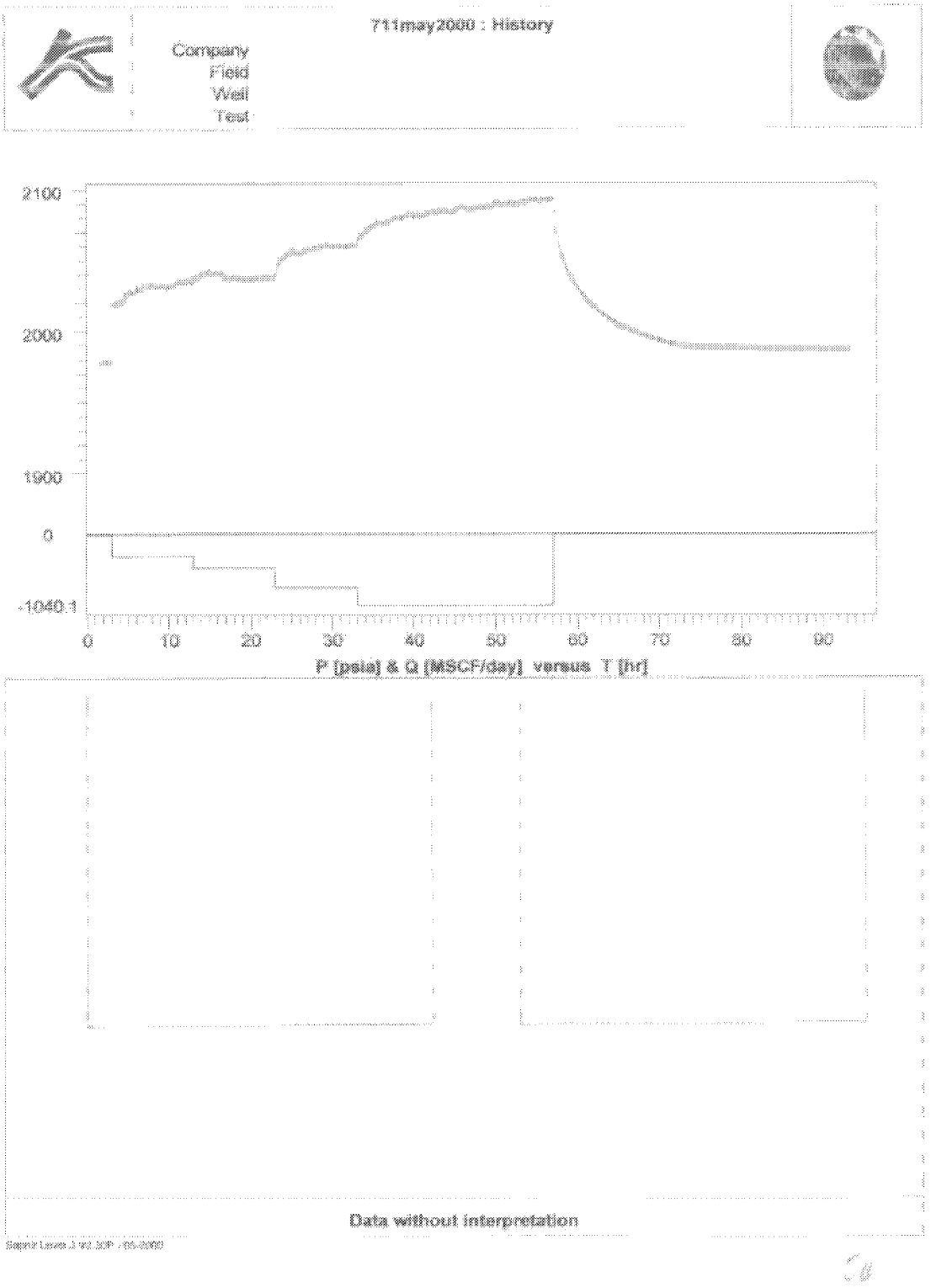
Company
Field
Well
Test

Date
Gauge
Depth
Formation interval
Perforated interval

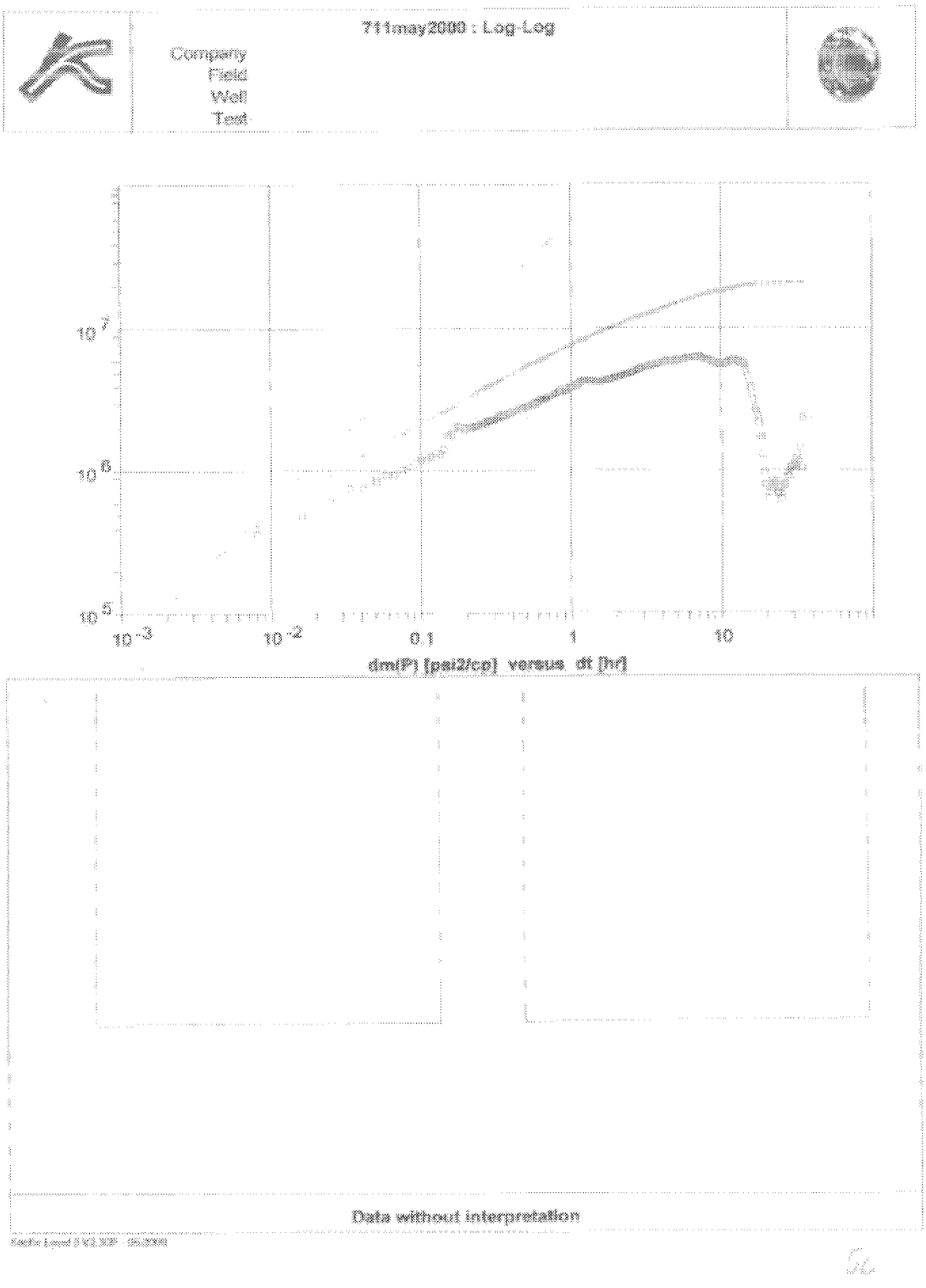
TEST TYPE	Standard	FLUID TYPE	Gas
Porosity Phi (%)	18	Gas Gravity	0.7
Well Radius rw	0.225 ft		
Pay Zone h	90 ft	Reservoir T	96 °F
		Reservoir P	2000 psia
		Properties	@ Reservoir T&P
		Total Compr. ct	0.000207186 psi-1
		Viscosity	0.0004654 cp

Data without interpretation

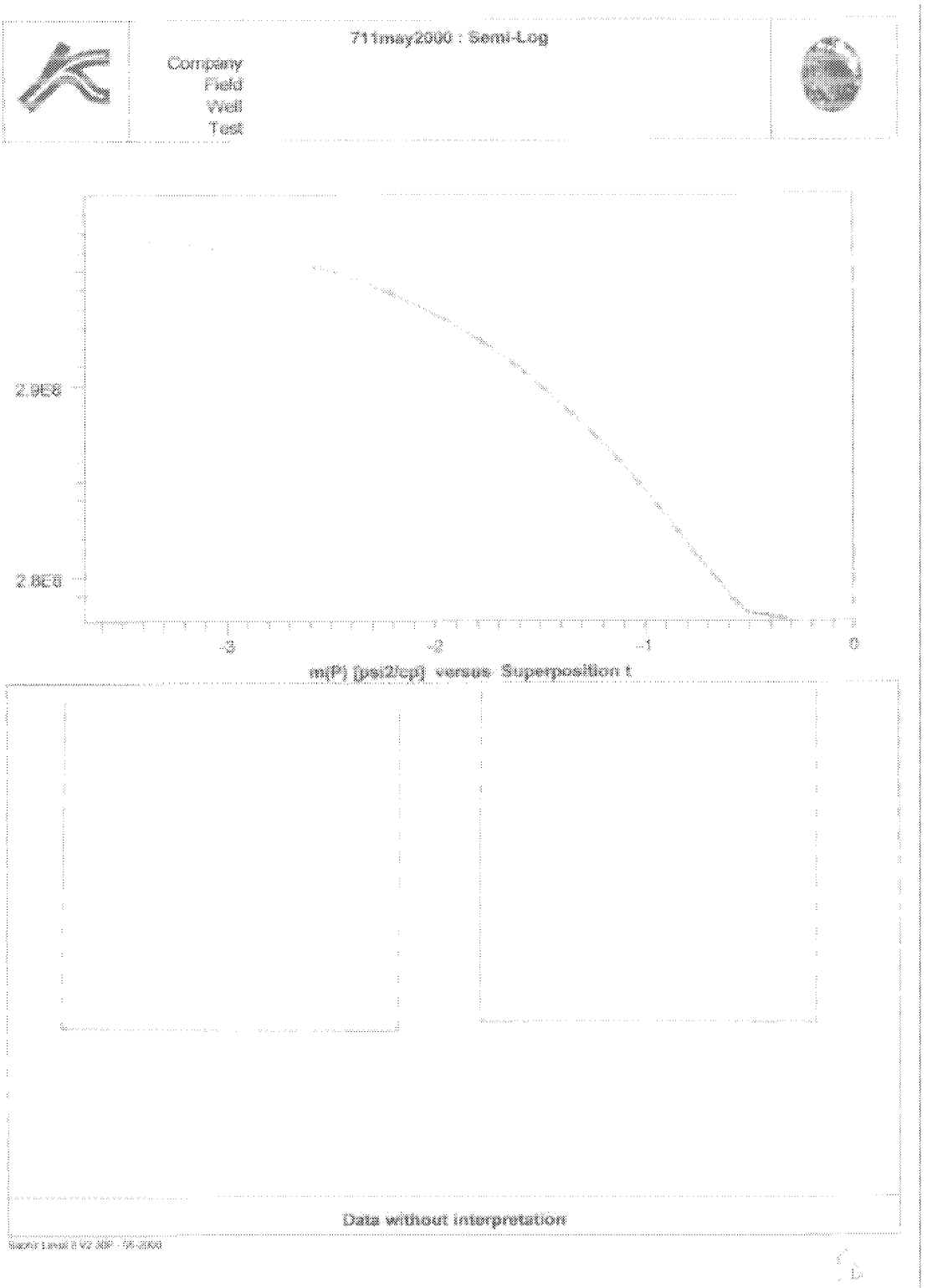
Appendix I


711may2000 : History
Company
Field
Well
Test
2100
2000
1900
0
-1040.1
0
10
20
30
40
50
60
70
80
90
P [psia] & Q [MSCF/day] versus T [hr]
Data without interpretation

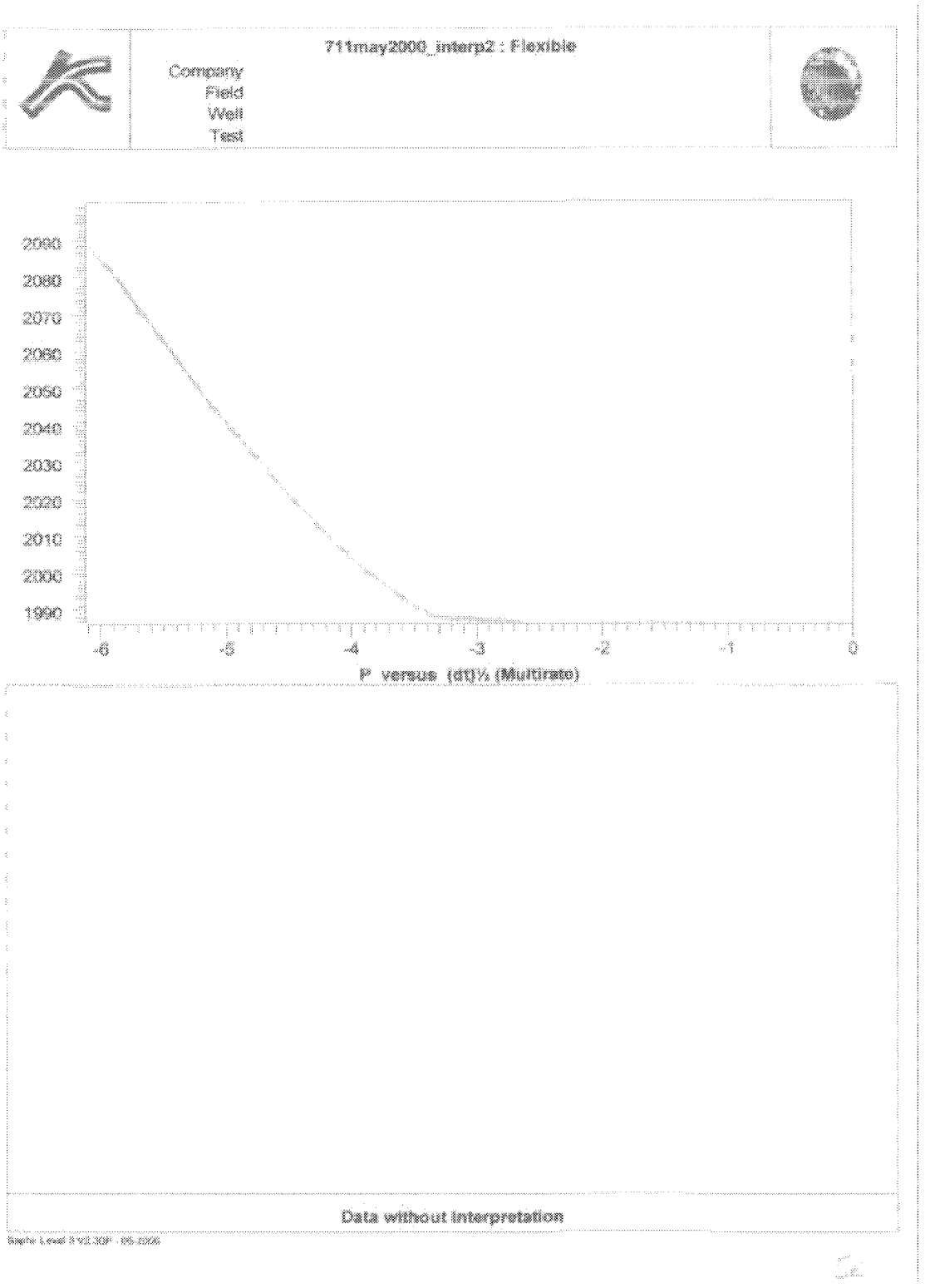
Appendix I


711may2000 : Log-Log
Company
Field
Well
Test
10^{7}
10^{6}
10^{5}
10^{-3}
10^{-2}
0.1
1
10
dm(P) [psi2/cp] versus dt [hr]
Data without interpretation

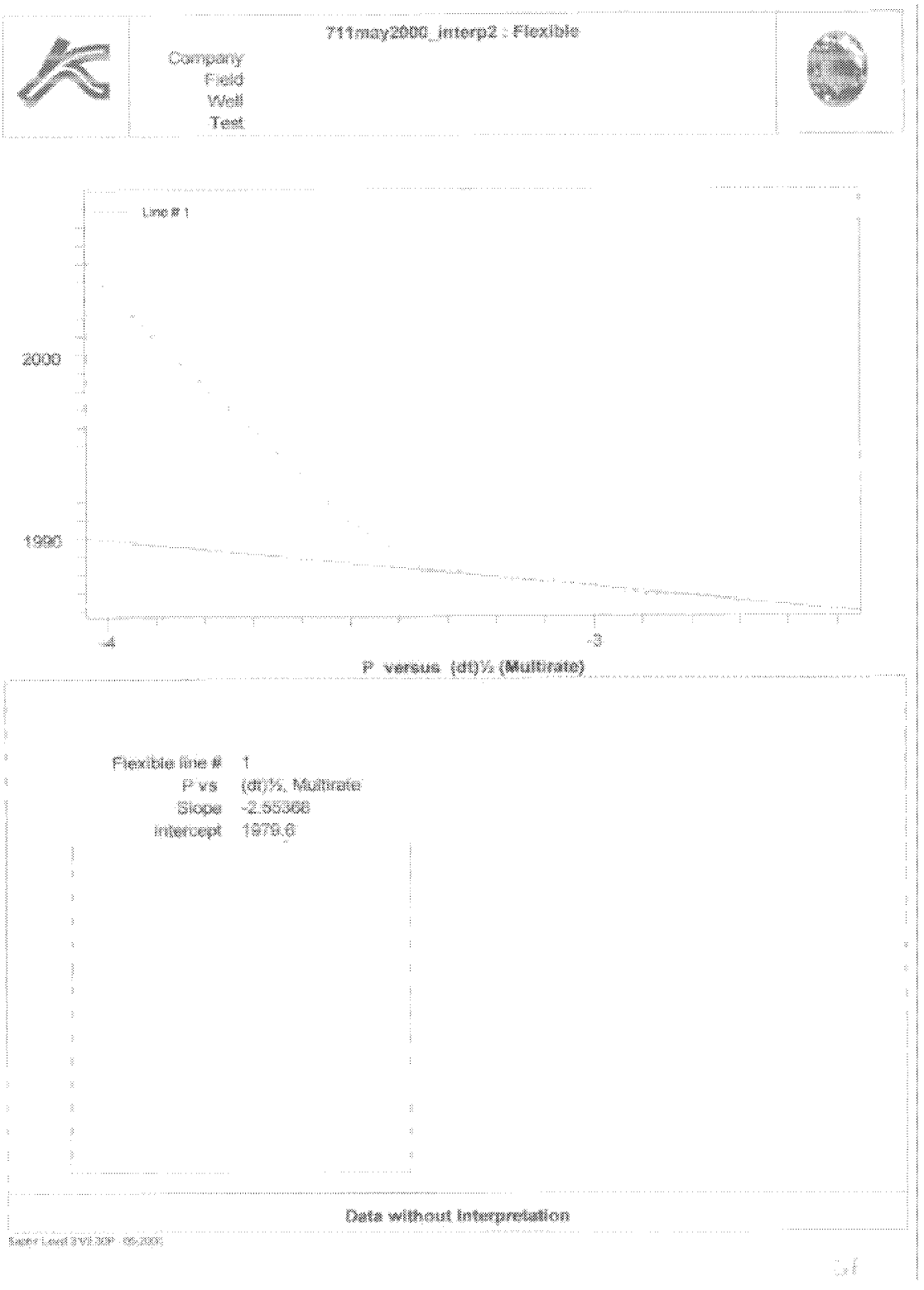
Appendix I


711may2000 : Semi-Log
Company
Field
Well
Test
2.9E8
2.8E8
-3
-2
-1
0
m(P) [psi2/cp] versus Superposition t
Data without interpretation

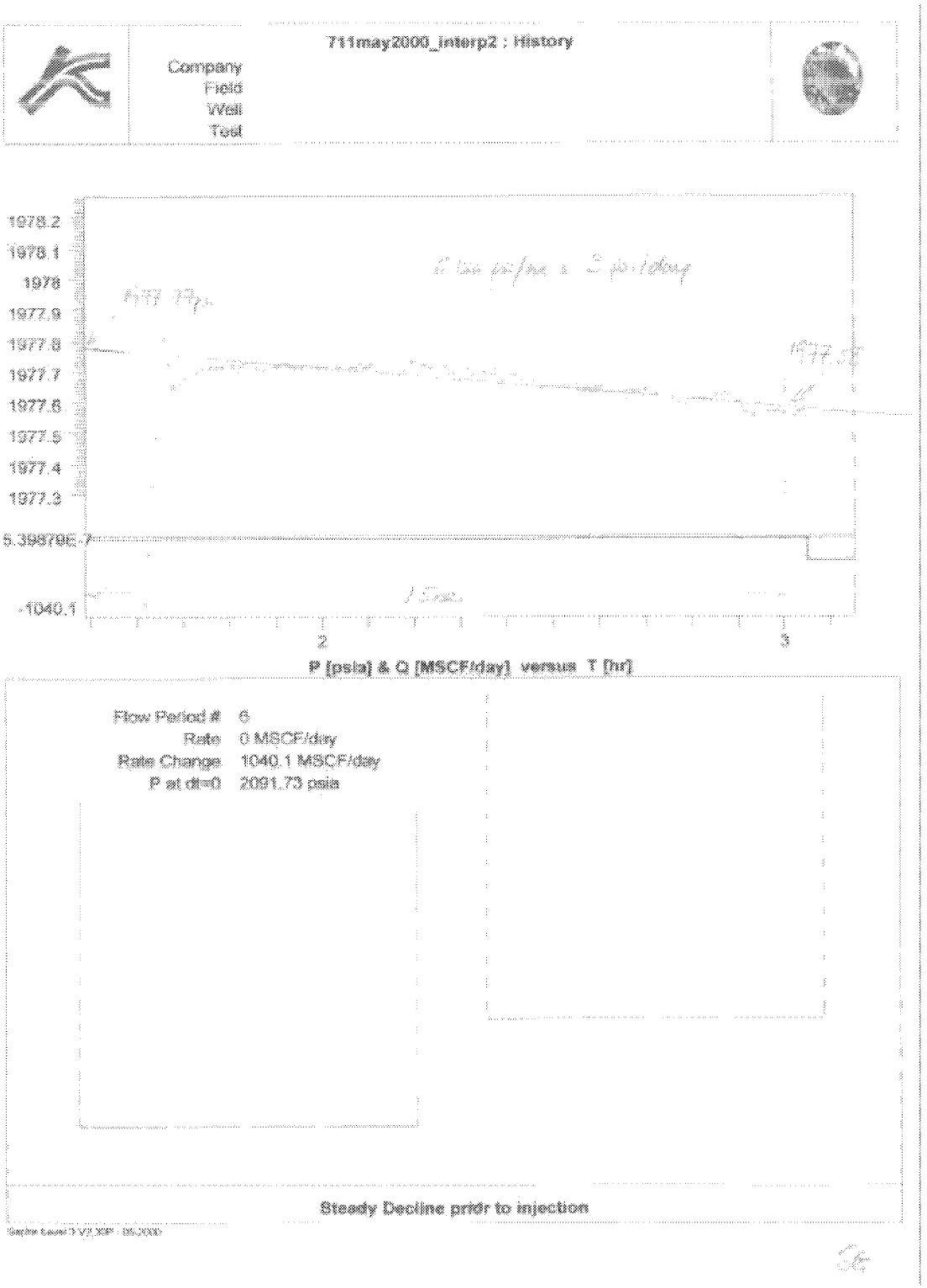
Appendix I


711may2000_interp2 : Flexible
Company
Field
Well
Test
2090
2080
2070
2060
2050
2040
2030
2020
2010
2000
1990
-6
-5
-4
-3
-2
-1
0
P_ versus (dt)½ (Multirate)
Data without interpretation

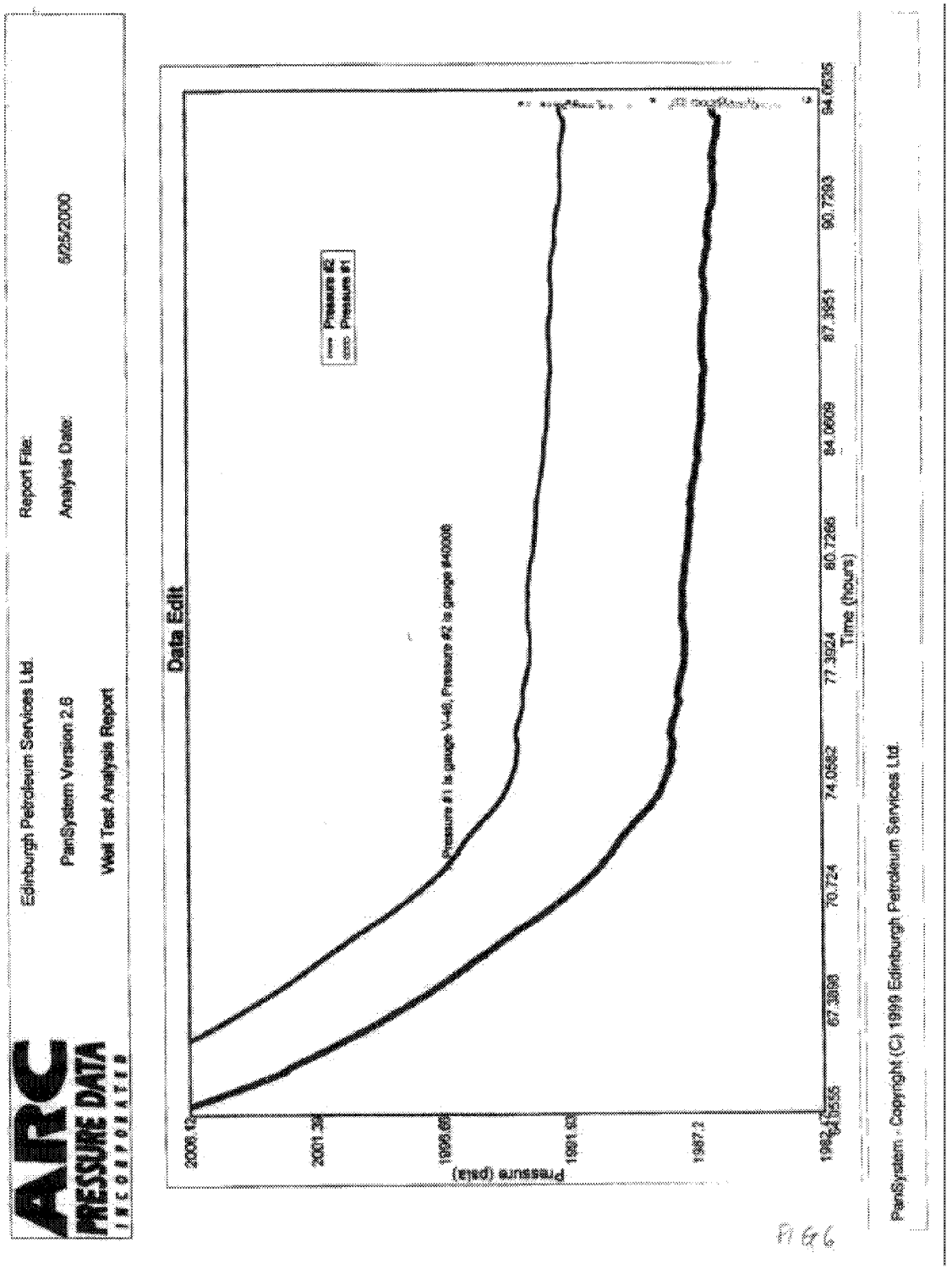
Appendix I

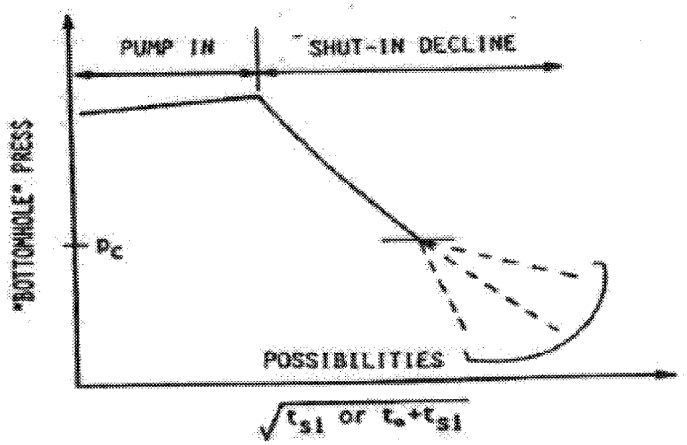

711may2000_interp2 : Flexible
Company
Field
Well
Test
Line # 1
2000
1980
-4
-3
P versus (dt)½ (Multirate)
Flexible line # 1
P vs (dt)½, Multirate
Slope -2.55368
Intercept 1979.6
Data without Interpretation

Appendix I


711may2000_interp2 : History
Company
Field
Well
Test
1978.2
1978.1
1978
1977.9
1977.8
1977.7
1977.6
1977.5
1977.4
1977.3
5.39878E-7
-1040.1
2
3
P [psia] & Q [MSCF/day] versus T [hr]
Flow Period # 6
Rate 0 MSCF/day
Rate Change 1040.1 MSCF/day
P at dt=0 2091.73 psia
Steady Decline prior to injection

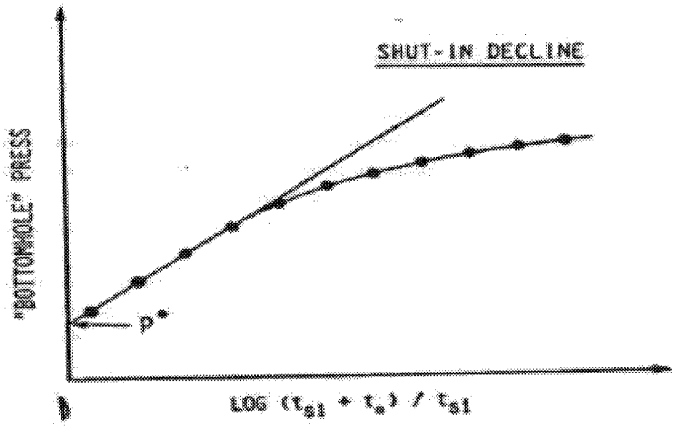
Appendix I


ARC
PRESSURE DATA
Edinburgh Petroleum Services Ltd.
PanSystem Version 2.8
Well Test Analysis Report
Report File:
Analysis Date:
6/28/2000
Data Edit
Pressure #2
Pressure #1
Pressure #1 is gauge V-46, Pressure #2 is gauge #40008
Pressure (psia)
2008.10
2001.34
1994.58
1987.82
1981.06
Time (hours)
67.3388
70.724
74.0582
77.3924
80.7266
84.0608
87.3951
90.7293
94.0635
PanSystem - Copyright (C) 1999 Edinburgh Petroleum Services Ltd.



t_{sl}=SHUT-IN TIME t_e=INJECTION TIME INTO FRACTURE.

Pump In/ Shut-In Decline Plot to Determine Closure Pressure



t_{sl}=SHUT-IN TIME t_e=INJECTION TIME INTO FRACTURE.

Horner-Type Plot of Shut-In Decline Pressures to Determine P*

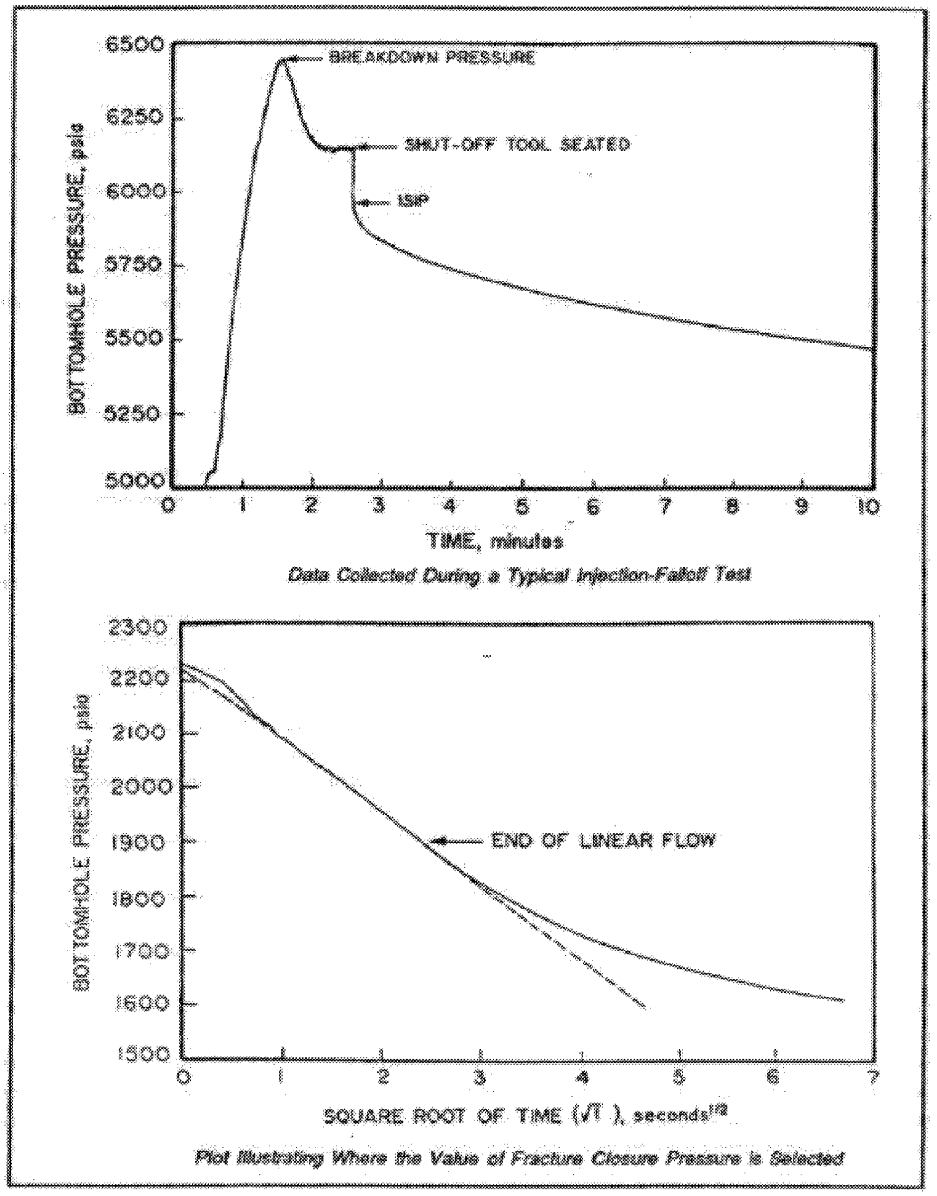
FIG 7A

CLOSURE PRESSURE DETERMINATION

Determination of closure pressure from pressure decline data is often NOT a trivial matter. Hypothetically, closure pressure should be repeatable and determined as the pressure at which the pressure decline curve deviates from linear response on a pressure vs. square-root of time graph.

Leak-off is assumed to be a function of the square-root of time. Consequently, as the fracture closes, the pressure response should be linear on a square-root of time graph. Once the fracture closes, the leak-off area is greatly reduced and the pressure decline should flatten out. Often, however, the pressure decline will actually steepen (increased leak-off?). In addition, a pressure decline curve will often exhibit multiple linear regions and picking the closure pressure becomes difficult.

The Gas Research Institute has obtained several hundred frac pressure decline datasets (from SFE and Co-op wells) and will eventually analyze non-standard decline behavior.



Data Collected During a Typical Injection-Falloff Test

Plot Illustrating Where the Value of Fracture Closure Pressure is Selected

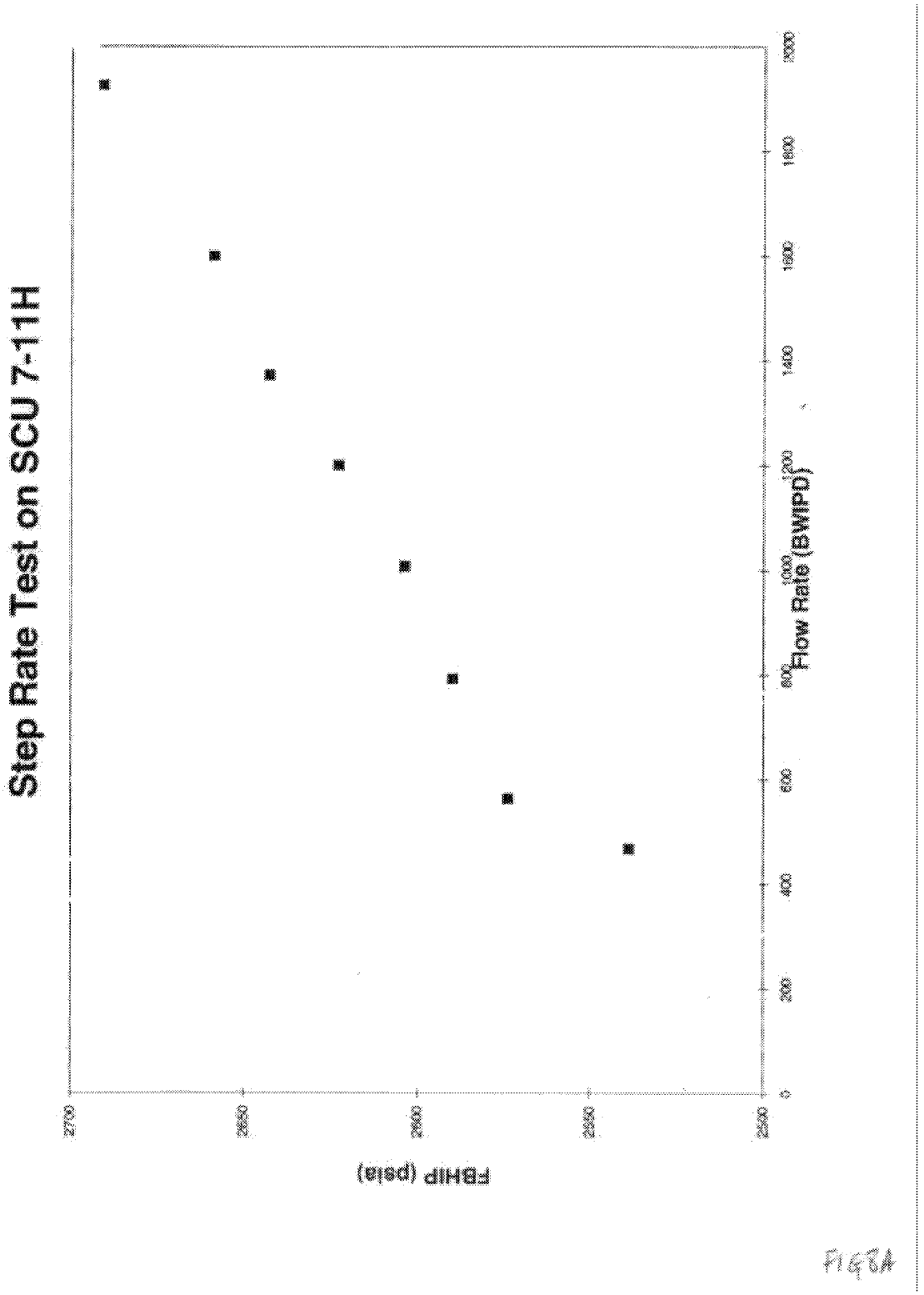

Step Rate Test on SCU 7-11H
FBHP (psia)
2700
2650
2600
2550
2500
Flow Rate (BWIPD)
0
200
400
600
800
1000
1200
1400
1600
1800
2000

FIG 8A

Sheet1

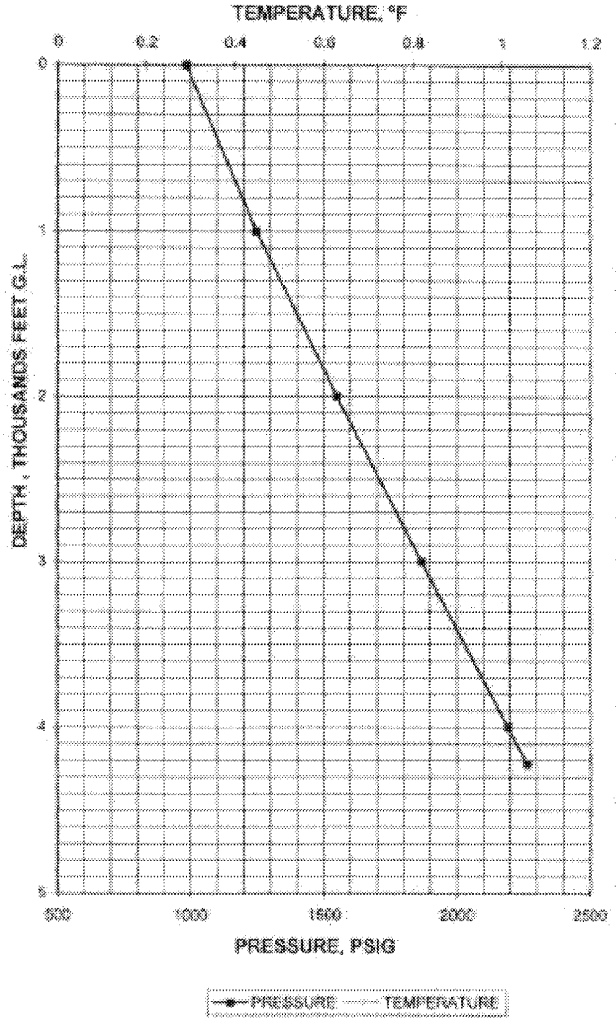
Steprate Test For Well 7C11H; August 27, 1996				
Time	Wellhead Pressure	Rate	Bottomhole Pressure	Comments
9:20	265	7777	2500	Rate unstable, probably < 400
9:30	380	477	2522	
9:45	390	480	2528	
10:00	390	471	2532	
10:15	395	468	2536	
10:30	400	466	2539	Increase rate to 600
10:45	420	574	2559	
11:00	430	565	2567	
11:15	430	568	2572	
11:30	430	563	2574	Increase rate to 800
11:45	450	793	2589	
12:00	450	792	2591	
12:15	450	793	2590	
12:30	450	792	2590	Increase rate to 1000
12:45		1044	2600	
13:00	470	1070	2602	
13:15	470	1066	2602	
13:30	470	1002	2603	
13:45	470	1007	2604	Increase rate to 1200
14:00	485	1152	2611	
14:15	485	1173	2614	
14:30	490	1238	2619	
14:45	490	1190	2621	
15:00	495	1199	2623	Increase rate to 1400
15:15	505	1413	2631	
15:30	510	1396	2635	
15:45	510	1389	2638	
16:00	520	1371	2643	Increase rate to 1600
16:15	530	1612	2649	
16:30	530	1612	2655	
16:45	540	1599	2659	Increase rate to 2000
17:00	565	1979	2676	
17:15	570	1972	2682	
17:30	578	1937	2687	
17:52	580	1927	2691	
18:00				Shut-In for falloff

Page 1

ARC PRESSURE DATA INCORPORATED

WELL GRADIENT SHEET

COMPANY	PHILLIPS PETROLEUM CO.	LEASE	SOUTH COMDEN UNIT	WELL NO.	7C-11H
FIELD		COUNTY ECTOR		STATE	TX
FORMATION		SHUT IN DATE & TIME		HOURS SHUT IN	
TEST DATE	2/21/00	TIME 10:22	WELL STATUS INJECTING	JOB NUMBER	19544



MEAS DEPTH FEET G.L.	TRUE DEPTH FEET G.L.	TEMP °F	PRESSURE PSIG	GRADIENT PSI/FT
0	0		984.55	
1000	1000		1249.44	0.2649
2000	2000		1568.33	0.3089
3000	3000		1967.74	0.3174
4000	4000		2192.10	0.3244
4220	4220 R. D.		2264.11	0.3273

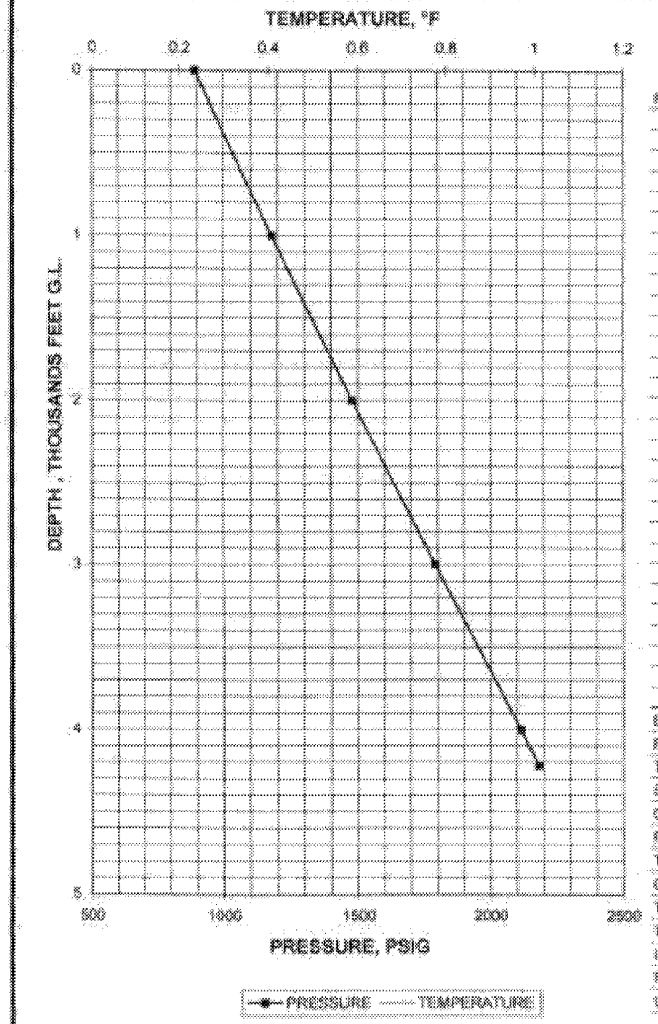
Elev. K.B. -	4856'	G.L. -	4881'
Pressure Datum			
Tubing	3 1/2"	Depth	4808'
S.N.	2.313"	Depth	4838'
Casing	7"	Depth	4907'
Perforations	4907' - 6244' OH		
Total Depth	6244'		
Casing Pressure	PACKER @ 4879'		
Tubing Pressure	983 DWO		
Temp. @	4220' =	96.15°	
Instrument No.	1-75		
Run By	MAX WHEELER		
Calculated By	HUB HAGLER		

Fig 7A

ARC PRESSURE DATA INCORPORATED

WELL GRADIENT SHEET

COMPANY	PHILLIPS PETROLEUM CO.	LEASE	SOUTH COMODEN UNIT	WELL NO.	7C-11H
FIELD		COUNTY	ECTOR	STATE	TX
FORMATION		SHUT IN DATE & TIME	2/21/00 11:22	HOURS SHUT IN	141.63
TEST DATE	2/27/00	TIME	8:53	WELL STATUS	SHUT IN
				JOB NUMBER	19544



MEAS. DEPTH FEET G.L.	TRUE DEPTH FEET G.L.	TEMP. °F	PRESSURE PSIG	GRADIENT PSI/FT
0	0		892.14	
1000	1000		1177.27	0.2851
2000	2000		1478.27	0.3020
3000	3000		1792.36	0.3138
4000	4000		2114.36	0.3220
4220	4220 R. D.		2181.56	0.3066

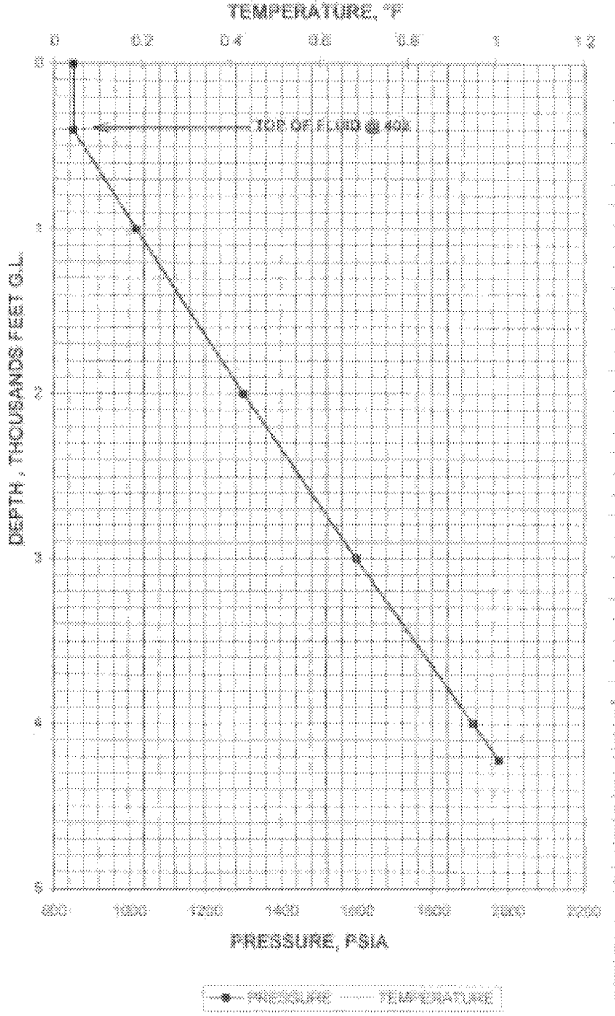
Elev. K.B. -	4666'	G.L. -	4681'
Pressure Datum			
Tubing	3 1/2"	Depth	4666'
S.N.	2.313"	Depth	4666'
Casing	7"	Depth	4907'
Perforations	4907' - 6244' OH		
Total Depth	6244'		
Casing Pressure	PACKER @ 4878'		
Tubing Pressure	893 PMG		
Temp. @	4220' =	94.82°	
Instrument No.	T-75		
Run By	MAX WHEELER		
Calculated By	HJB HAGLER		

Page

ARC PRESSURE DATA INCORPORATED

WELL GRADIENT SHEET

COMPANY	PHILLIPS PETROLEUM CO.	LEASE	SOUTH COMANCHE UNIT	WELL NO.	7C-11H
FIELD		COUNTY ECTOR		STATE	TX
FORMATION		SHUT IN DATE & TIME		HOURS SHUT IN	
TEST DATE	8/17/02	TIME 12:35	WELL STATUS SHUT IN	JOB NUMBER	19344A

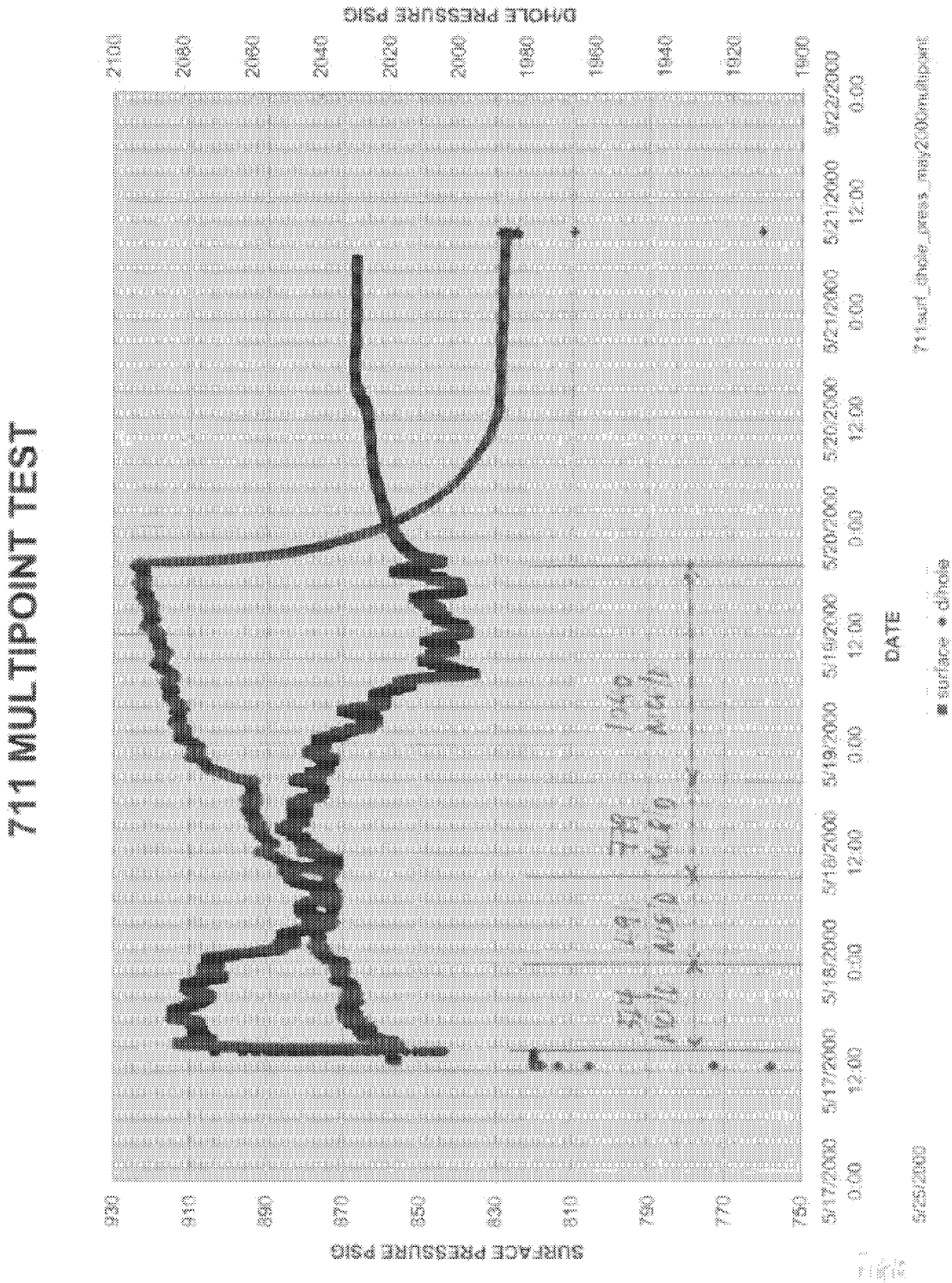


MEAS DEPTH FEET G.L.	TRUE DEPTH FEET G.L.	TEMP °F	PRESSURE PSIA	GRADIENT PSI/FT
0	0		650.01	
1000	1000		1019.31	0.1685
2000	2000		1309.88	0.2817
3000	3000		1597.60	0.2963
4000	4000		1908.60	0.3109
4220	4220 R. D.		1977.70	0.3132

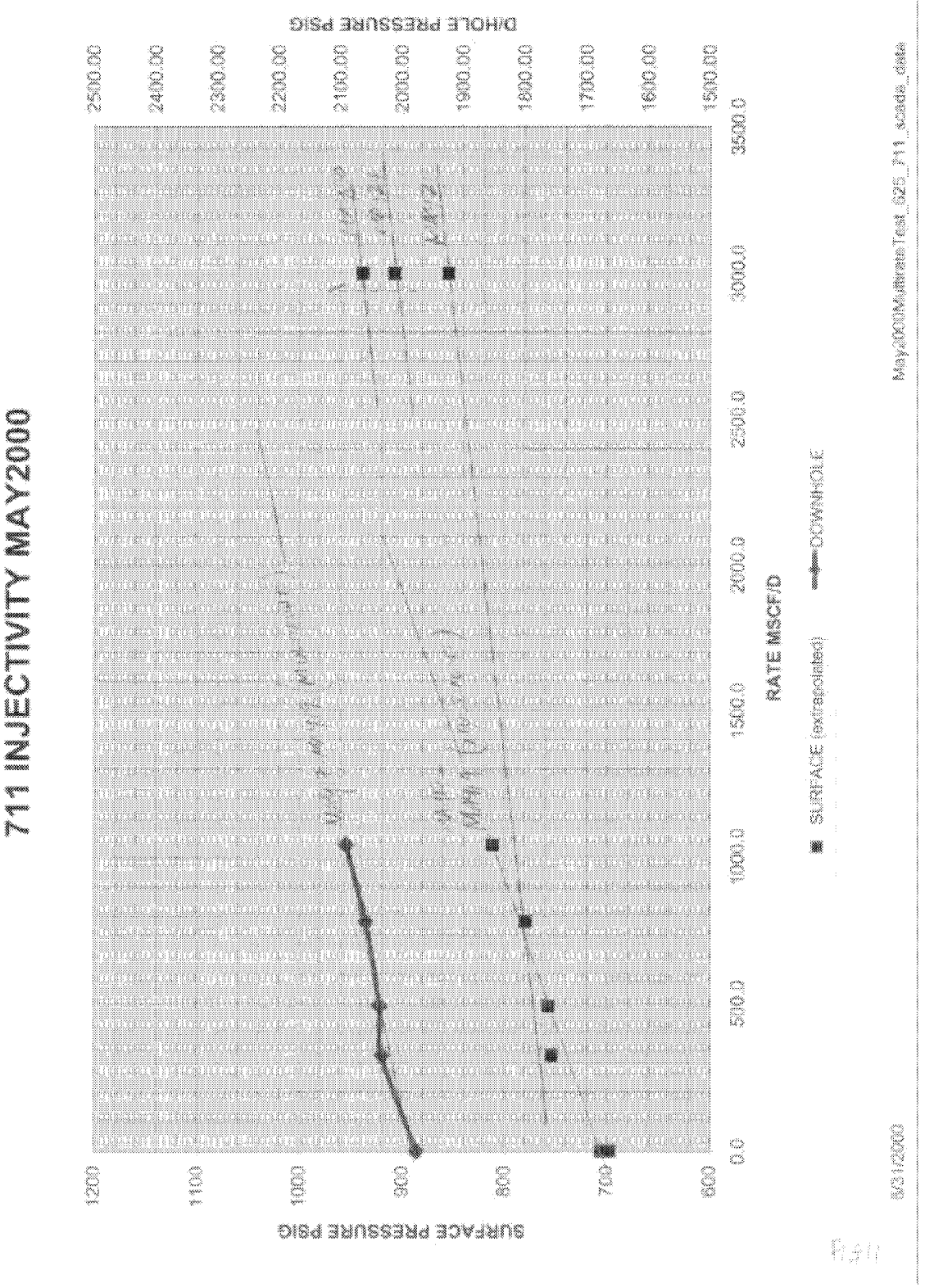
Elev. K.B.	17' AGL	G.L.	
Pressure Datum			
Tubing	3 1/2"	Depth	4958'
S.N.	2.813"	Depth	4959'
Casing	7"	Depth	4967'
Perforations	4807' - 5244' OH		
Total Depth	5244'		
Casing Pressure	PACKER @ 4670'		
Tubing Pressure	851 DWG		
Temp. @	4220	=	94.81°
Instrument No.	V-46		
Run By	MAX WHEELER		
Calculated By	HUB HAGLER		

1696

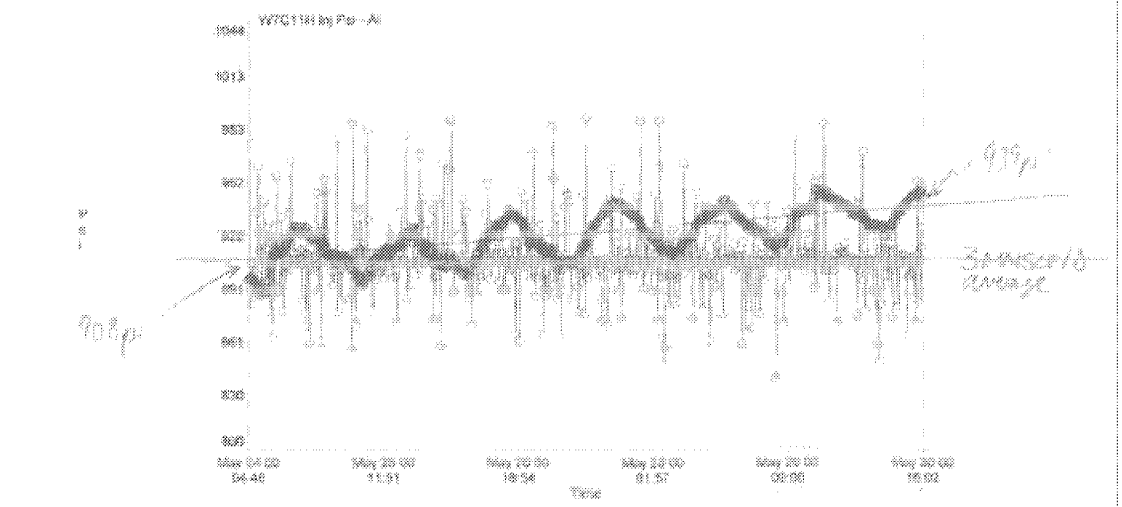
Appendix I


711 MULTIPOINT TEST
SURFACE PRESSURE PSIG
DHOLE PRESSURE PSIG
DATE
surface
dhole
711surf_dhole_press_may2000multipoint

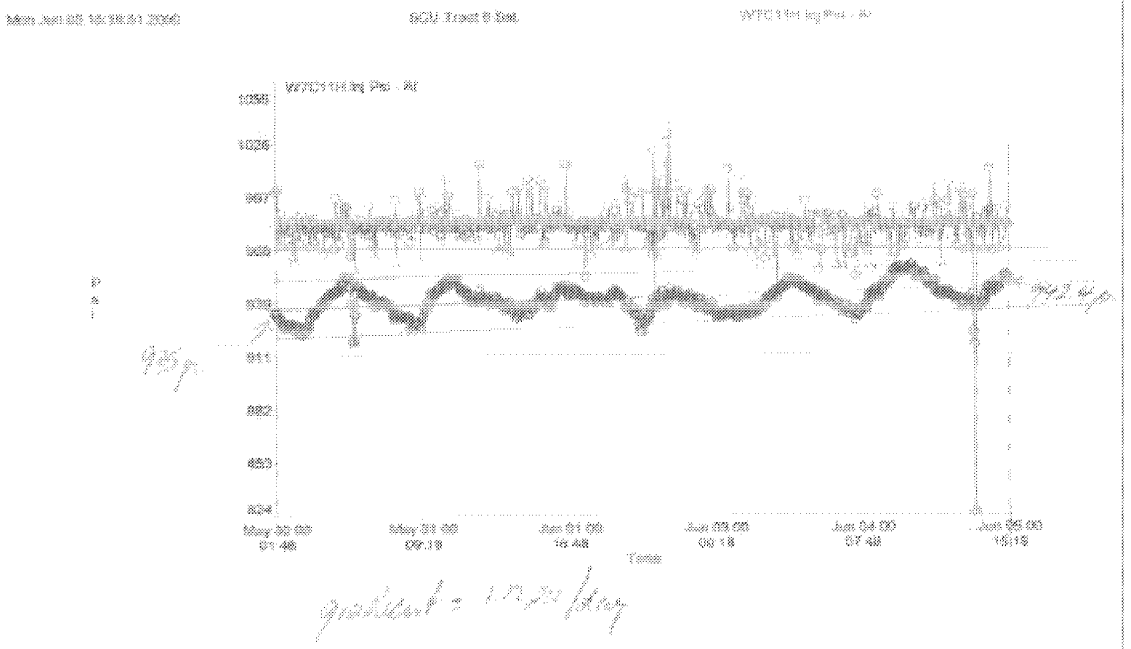
Appendix I


711 INJECTIVITY MAY2000
D/HOLE PRESSURE PSIG
2500.00
2400.00
2300.00
2200.00
2100.00
2000.00
1900.00
1800.00
1700.00
1600.00
1500.00
3500.0
3000.0
2500.0
2000.0
1500.0
1000.0
500.0
0.0
RATE MSCF/D
SURFACE (extrapolated)
DOWNHOLE
SURFACE PRESSURE PSIG
1200
1100
1000
900
800
700
600
May2000Multirate Test_625_711_scada_data
6/5/2000

Appendix I



Appendix I



625_feb2000_mayinterp : Main Results

Company
Field
Well
Test

Date
Gauge
Depth
Formation interval
Perforated interval

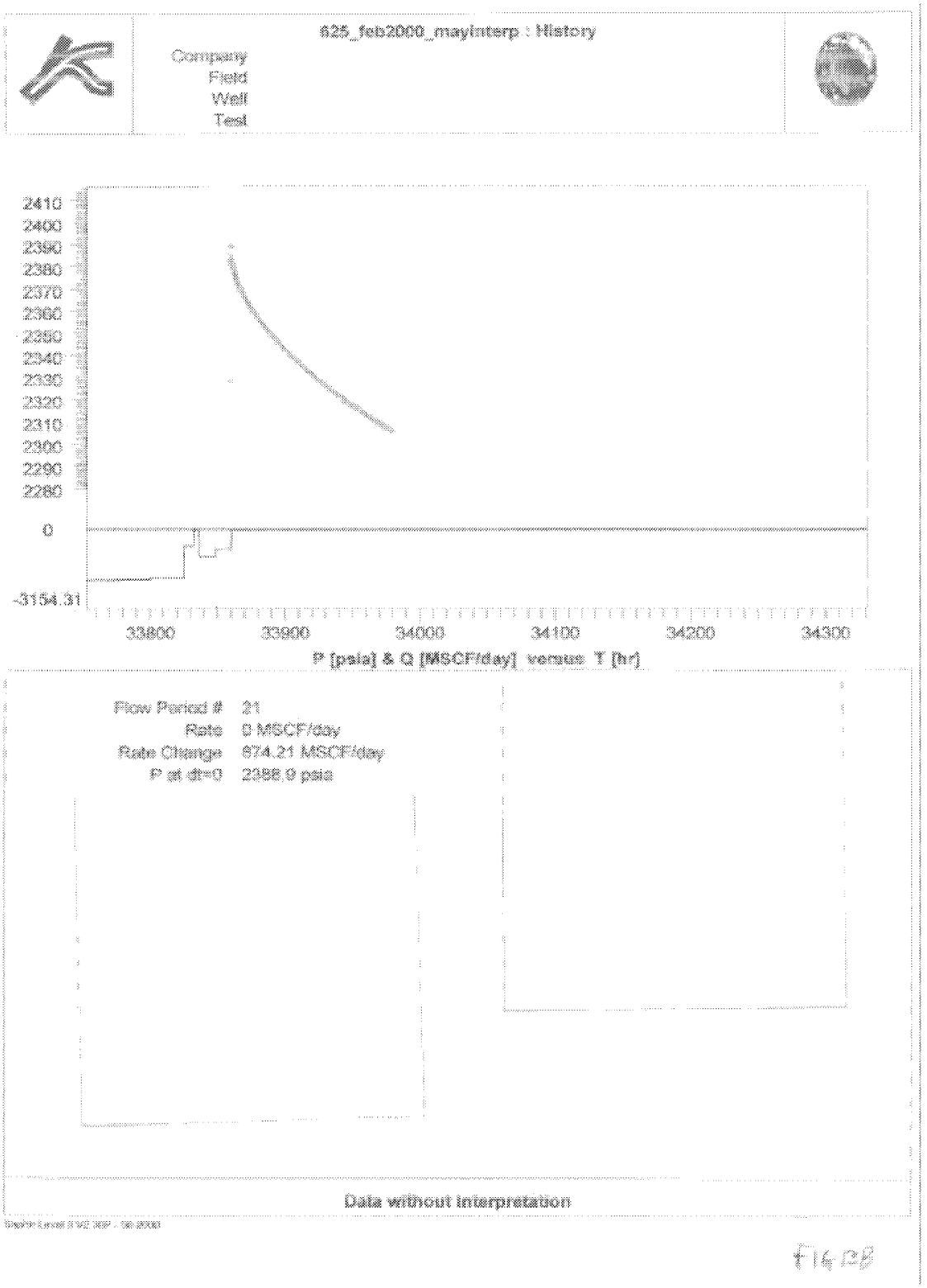
TEST TYPE	Standard	FLUID TYPE	Gas
Porosity Phi (%)	16	Gas Gravity	0.7
Well Radius rw	0.255 ft		
Pay Zone h	90 ft	Reservoir T	96 °F
		Reservoir P	2300 psia
		Properties	@ Reservoir T&P
		Total Compr. ct	0.000142615 psi-1
		Viscosity	0.0663058 cp

Flow Period #	21
Rate	0 MSCF/day
Rate Change	874.21 MSCF/day
P at dt=0	2388.9 psia

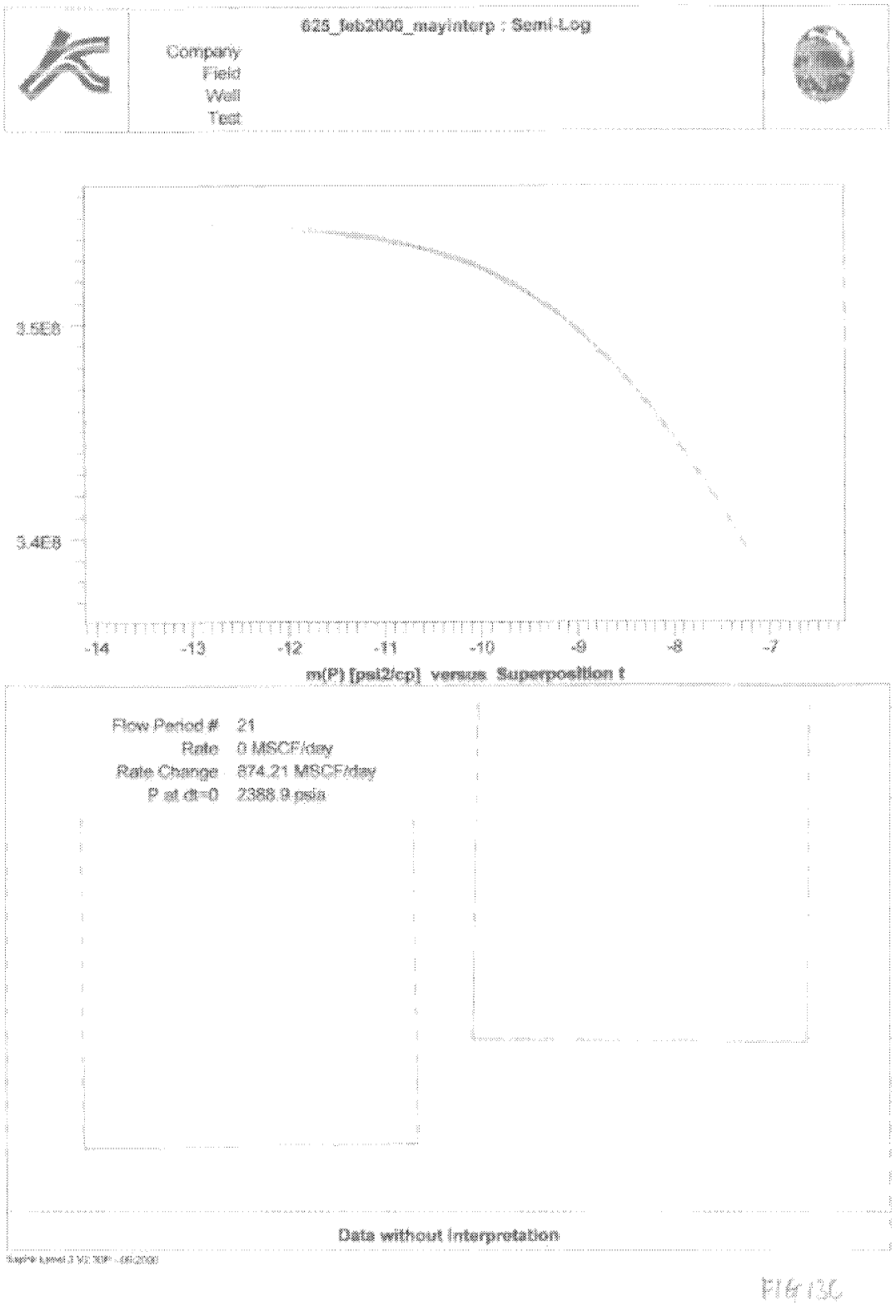
Data without interpretation

FIG 13A

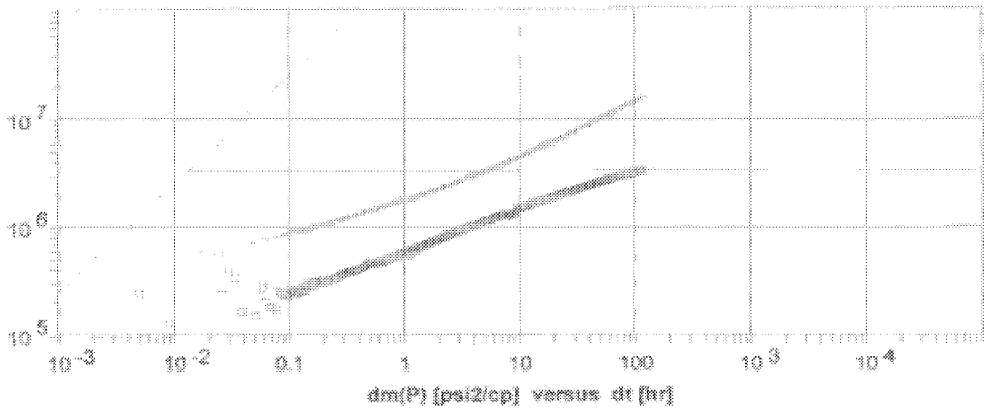
Appendix I


625_feb2000_mayinterp : History
Company
Field
Well
Test
2410
2400
2390
2380
2370
2360
2350
2340
2330
2320
2310
2300
2290
2280
0
-3154.31
33800
33900
34000
34100
34200
34300
P [psia] & Q [MSCF/day] versus T [hr]
Flow Period # 21
Rate 0 MSCF/day
Rate Change 674.21 MSCF/day
P at dt=0 2388.9 psia
Data without interpretation

Appendix I


625_feb2000_mayInterp : Semi-Log
Company
Field
Well
Test
3.5E8
3.4E8
-14
-13
-12
-11
-10
-9
-8
-7
m(P) [psi2/cp] versus Superposition t
Flow Period # 21
Rate 0 MSCF/day
Rate Change 874.21 MSCF/day
P at dt=0 2388.9 psia
Data without interpretation

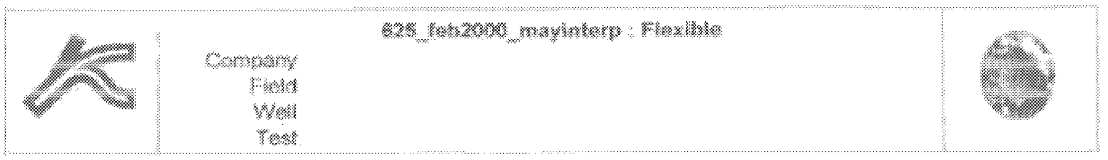
Appendix I

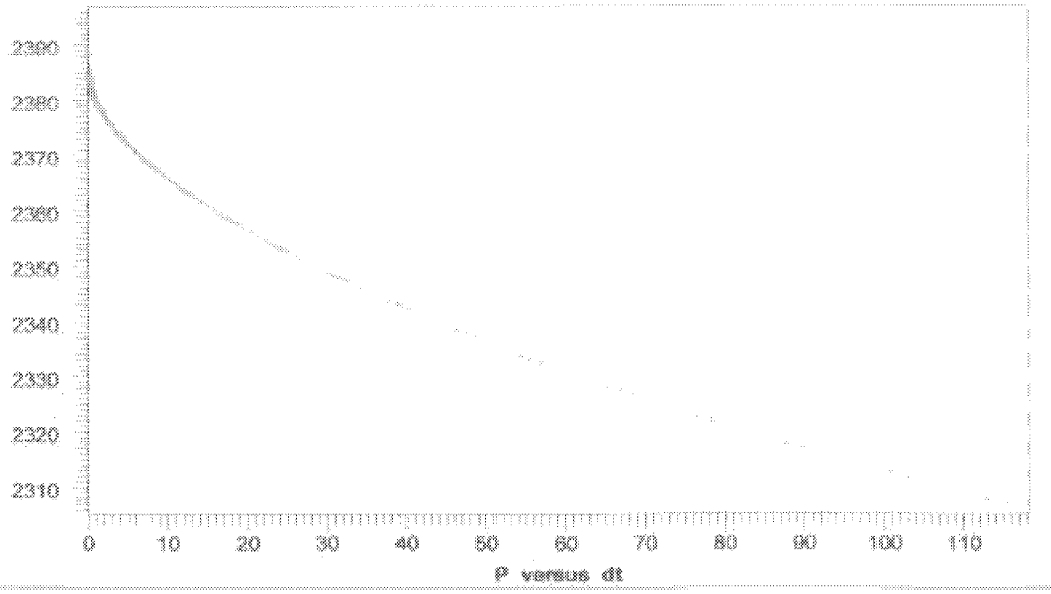


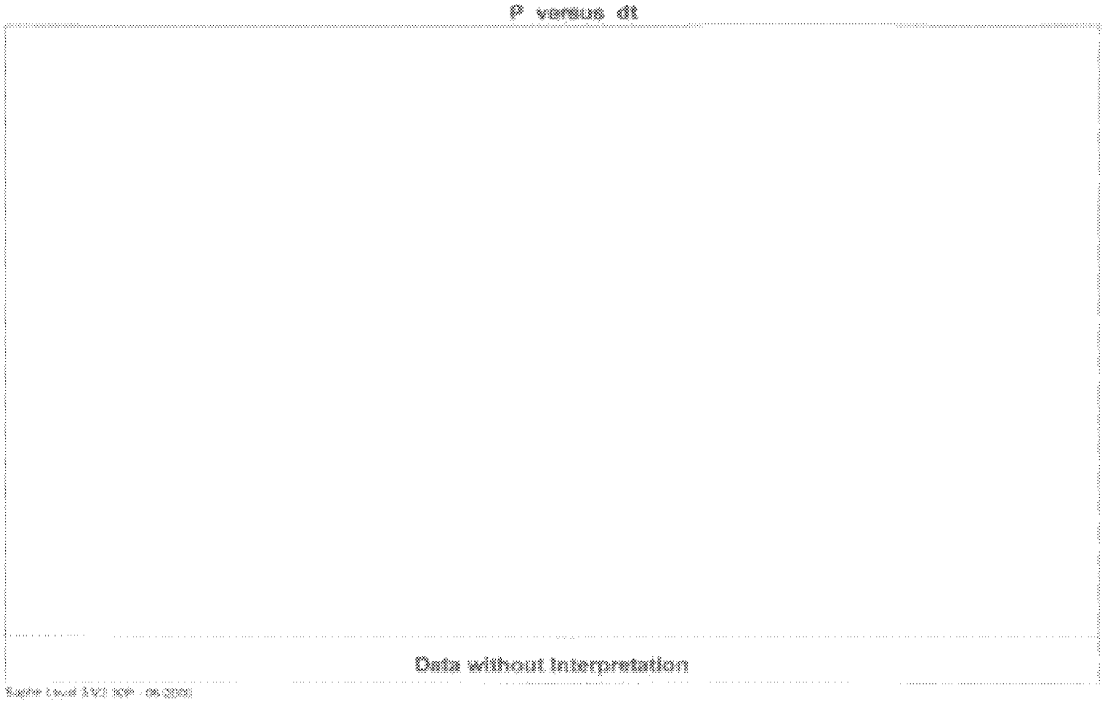
Flow Period # 21
Rate 0 MSCF/day
Rate Change 674.21 MSCF/day
P at dt=0 2398.9 psia
Smoothing 0.1

Data without interpretation

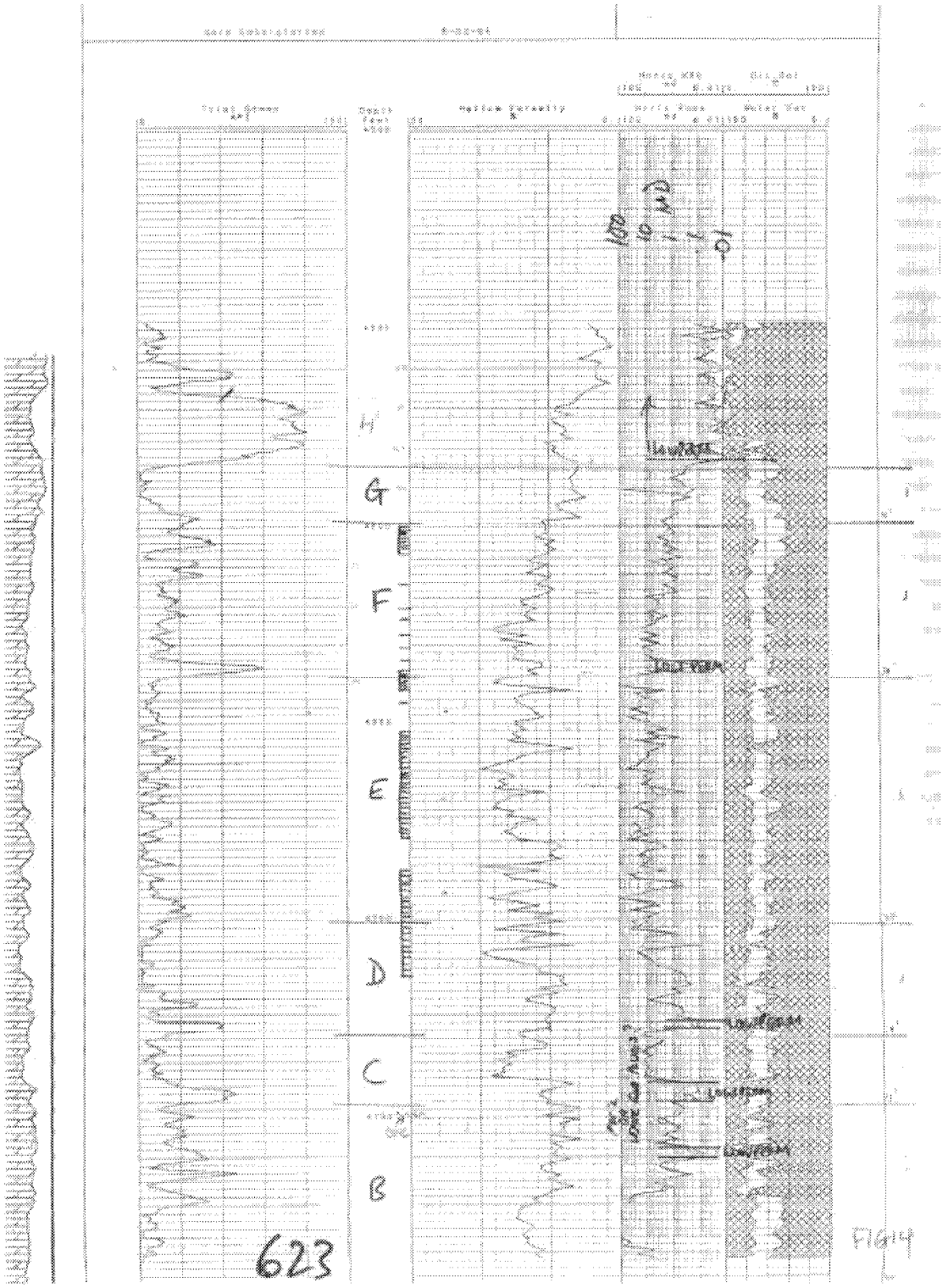
Appendix I


625_feb2000_mayinterp : Flexible
Company
Field
Well
Test


2390
2380
2370
2360
2350
2340
2330
2320
2310
0
10
20
30
40
50
60
70
80
90
100
110
P versus dt


Data without Interpretation

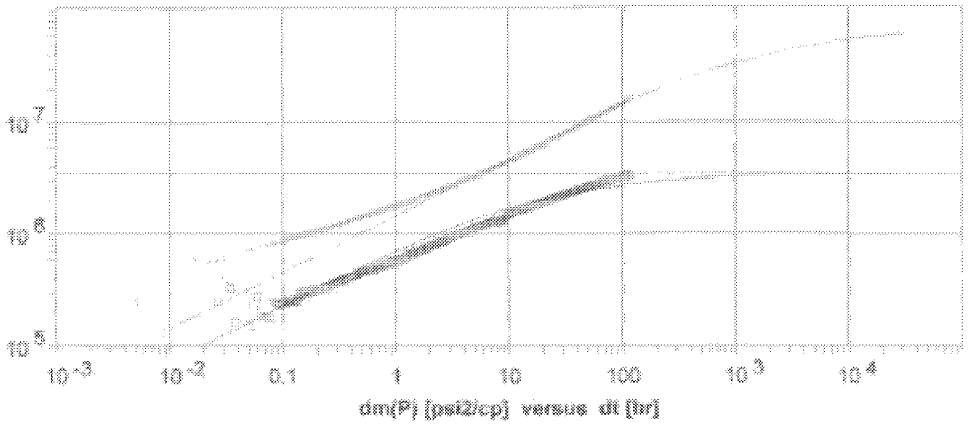
Appendix I



Appendix I

625_feb2000_mayinterp : Log-Log

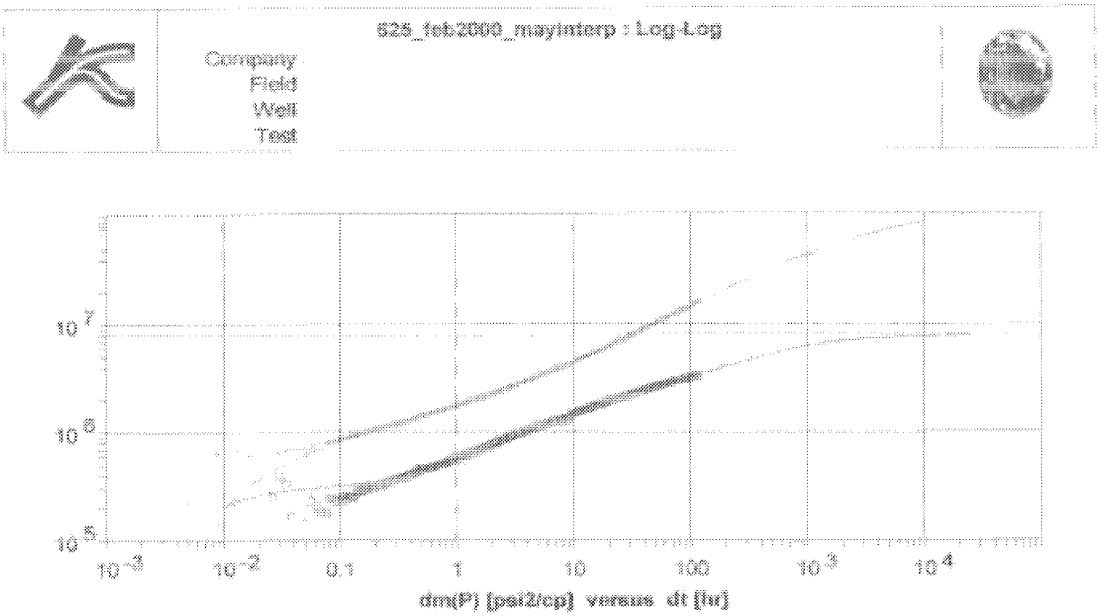
Company
Field
Well
Test



Flow Period #	21	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	874.21 MSCF/day	WELL	Storage & Skin
P at dt=0	2388.9 psia	Storage C	7.15E-11 STB/psi
Smoothing	0.1	Skin factor	-5.69
PI	2033.4 psia	Delta P Skin	-197.535 psia
Time Match	6.38E9 (hr)-1	kh	103 md.ft
Pressure Match	1.49E-7 (psi2/cp)-1	k	1.14 md
		Mobility k/mu	17.2
		Investig. R	274 ft
		Tested Volume	603561 Barrels

Using 90' thickness

Appendix I



Flow Period #	21	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	874.21 MSCF/day	WELL	Horizontal well
P at dt=0	2388.9 psia	Storage C	6.83E-9 STB/psi
Smoothing	0.1	Skin factor	-0.11
Pi	1767.66 psia	Delta P Skin	-8.4768 psia
		h	90 ft
Time Match	3.39E7 (hr)-1	hw	663 ft
Pressure Match	6.42E-8 (psi2/cp)-1	zw	22.5 ft
		kr h	44.4 md ft
		kr	0.49 md
		kz/kr	11
		kz	5.43 md
		Top	sealing
		Bottom	sealing
		Mobility kr/mu	7.44
		Investig. R	180 ft
		Tested Volume	261072 Barrels

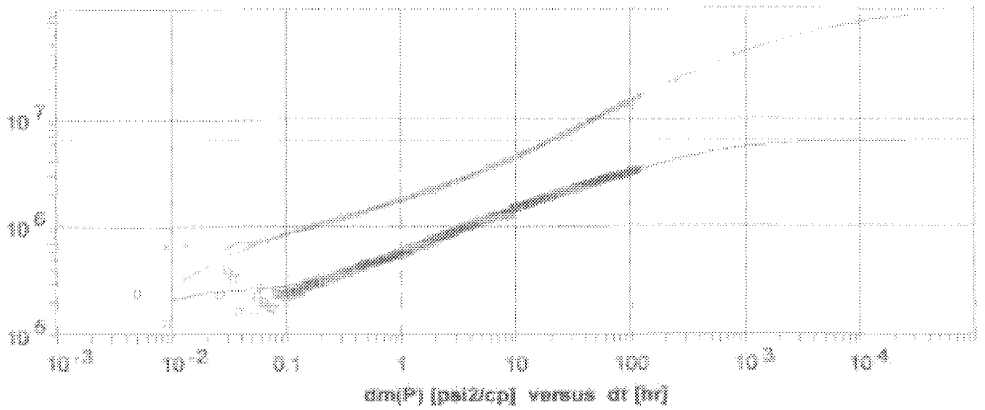
Horizontal well using 90' thickness

FIG 6A

Appendix I

625_feb2000_mayinterp : Log-Log

Company
Field
Well
Test



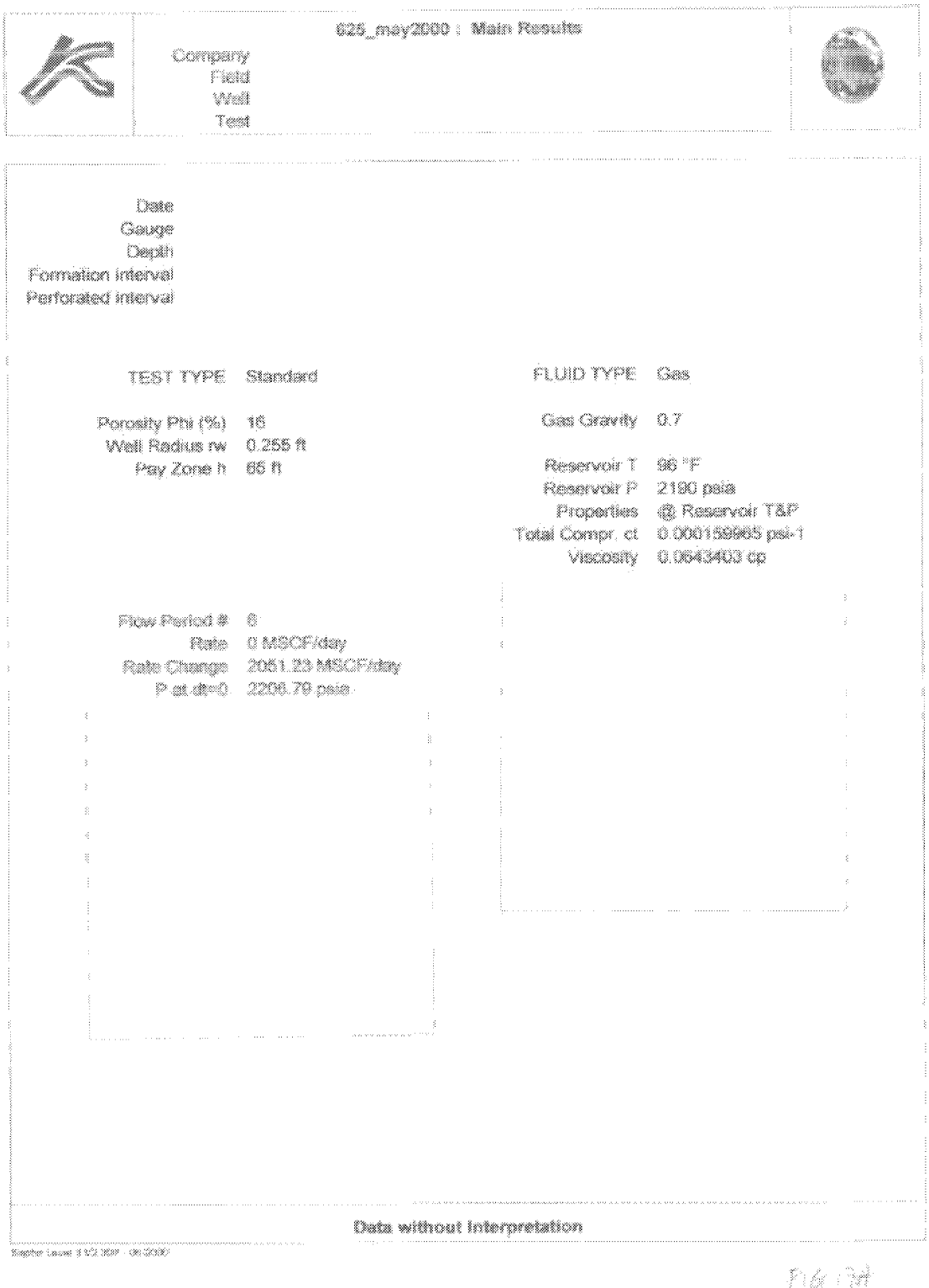
Flow Period #	21	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	874.21 MSCF/day	WELL	Horizontal well
P at dt=0	2388.9 psia	Storage C	6.19E-10 STB/psi
Smoothing	0.1	Skin factor	-0.11
Pi	1846.08 psia	Delta P Skin	-6.52895 psia
		h	65 ft
Time Match	4.02E8 (hr)-1	hw	645 ft
Pressure Match	8.1E-8 (psi2/cp)-1	zw	16.4 ft
		kr.h	56 md.ft
		kr	0.86 md
		kz/kr	5.29
		kz	4.55 md
		Top	sealing
		Bottom	sealing
		Mobility kr/mu	13
		Investig. R	238 ft
		Tested Volume	329187 Barrels

Horizontal well using 65' thickness

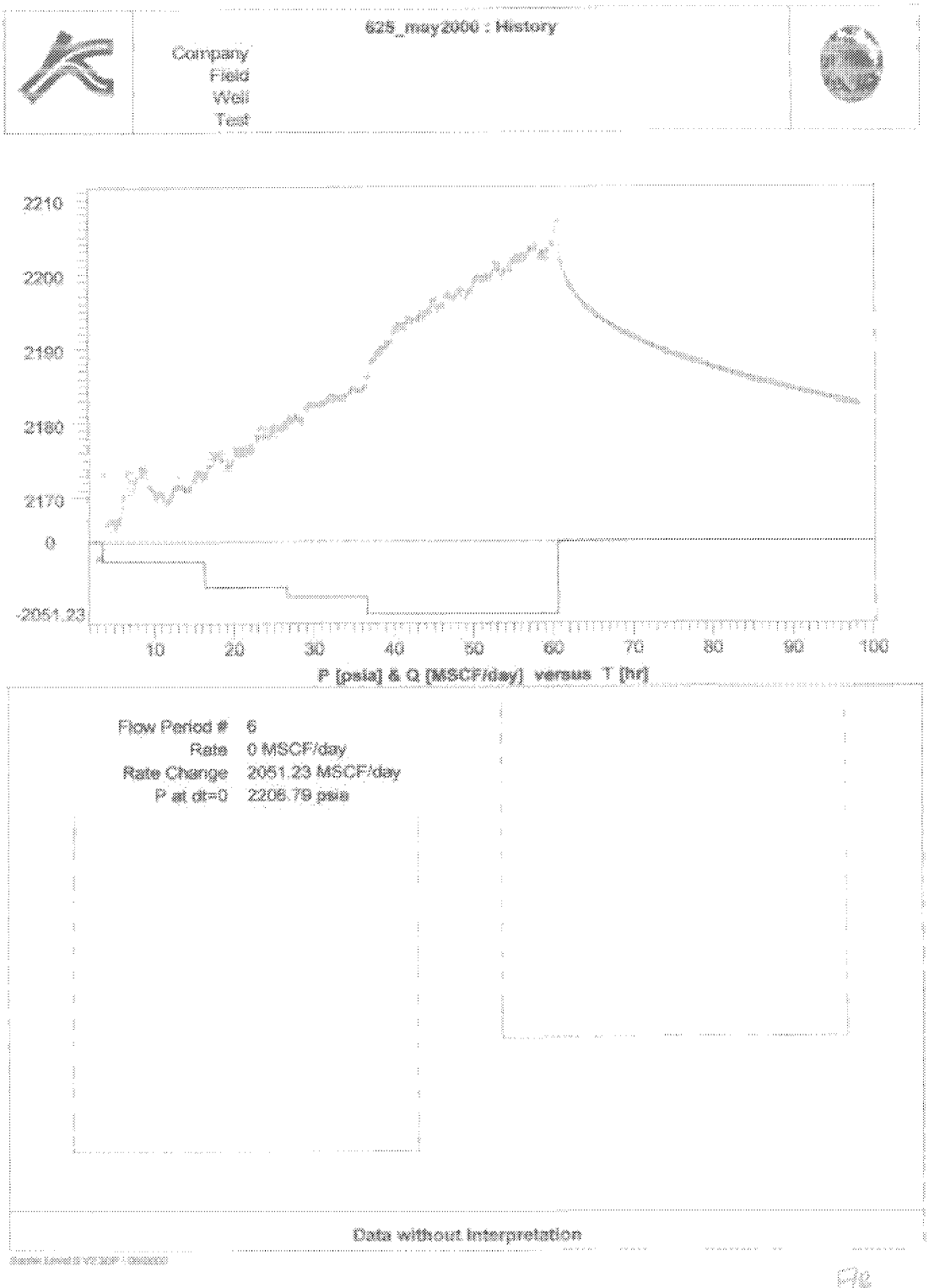
Sophi Level 3 V2.30F - 06-2000

FIG 16B

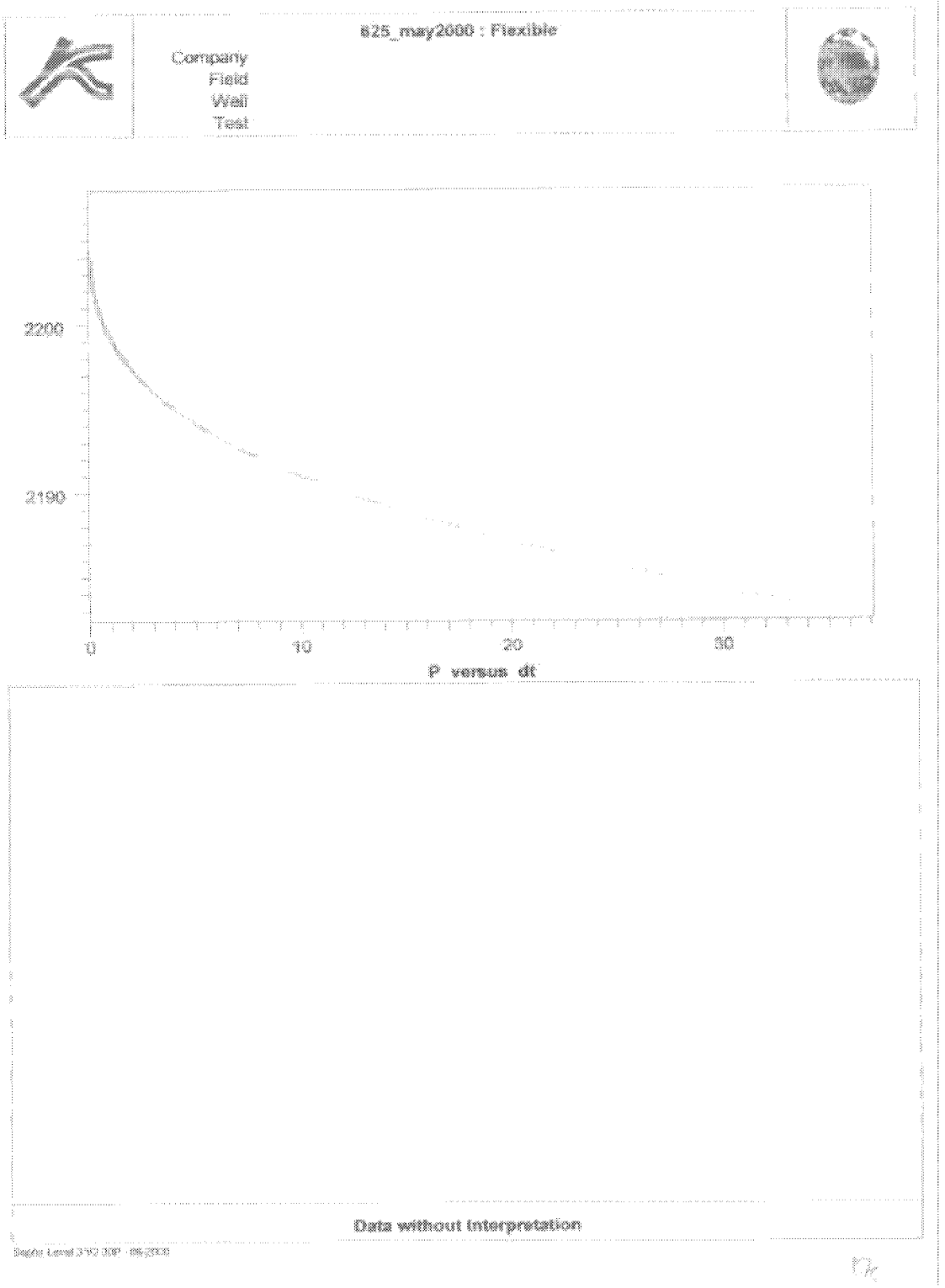
Appendix I


625_may2000 : Main Results
Company
Field
Well
Test
Date
Gauge
Depth
Formation interval
Perforated interval
TEST TYPE Standard
Porosity Phi (%) 16
Well Radius rw 0.255 ft
Pay Zone h 66 ft
FLUID TYPE Gas
Gas Gravity 0.7
Reservoir T 96 °F
Reservoir P 2190 psia
Properties @ Reservoir T&P
Total Compr. ct 0.000159965 psi-1
Viscosity 0.0643403 cp
Flow Period # 6
Rate 0 MSCF/day
Rate Change 2061.23 MSCF/day
P at dt=0 2206.79 psia
Data without Interpretation

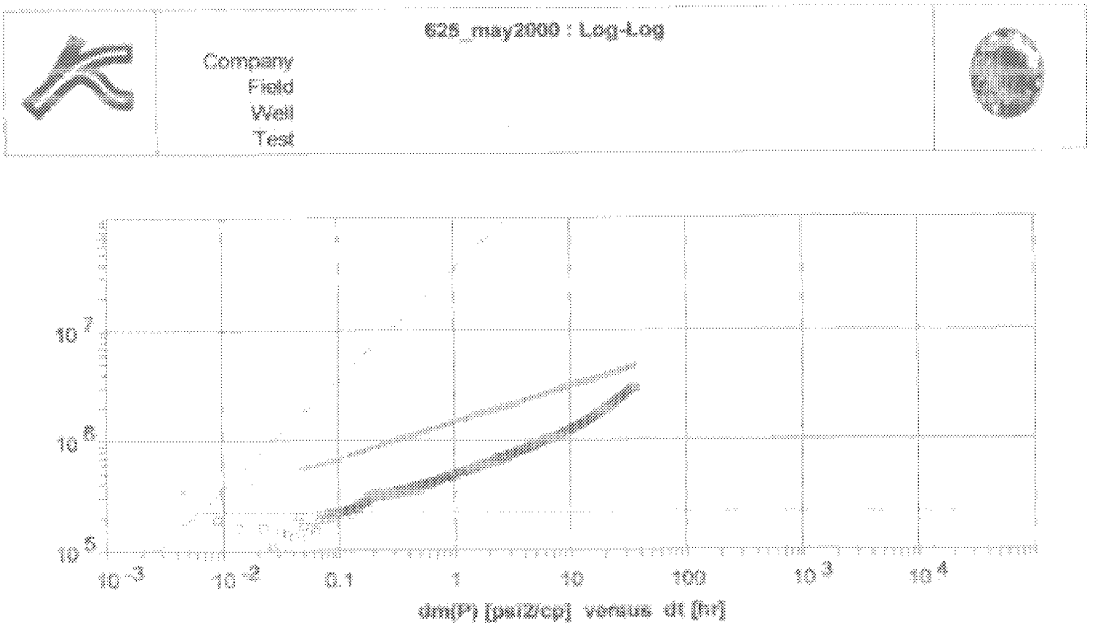
Appendix I

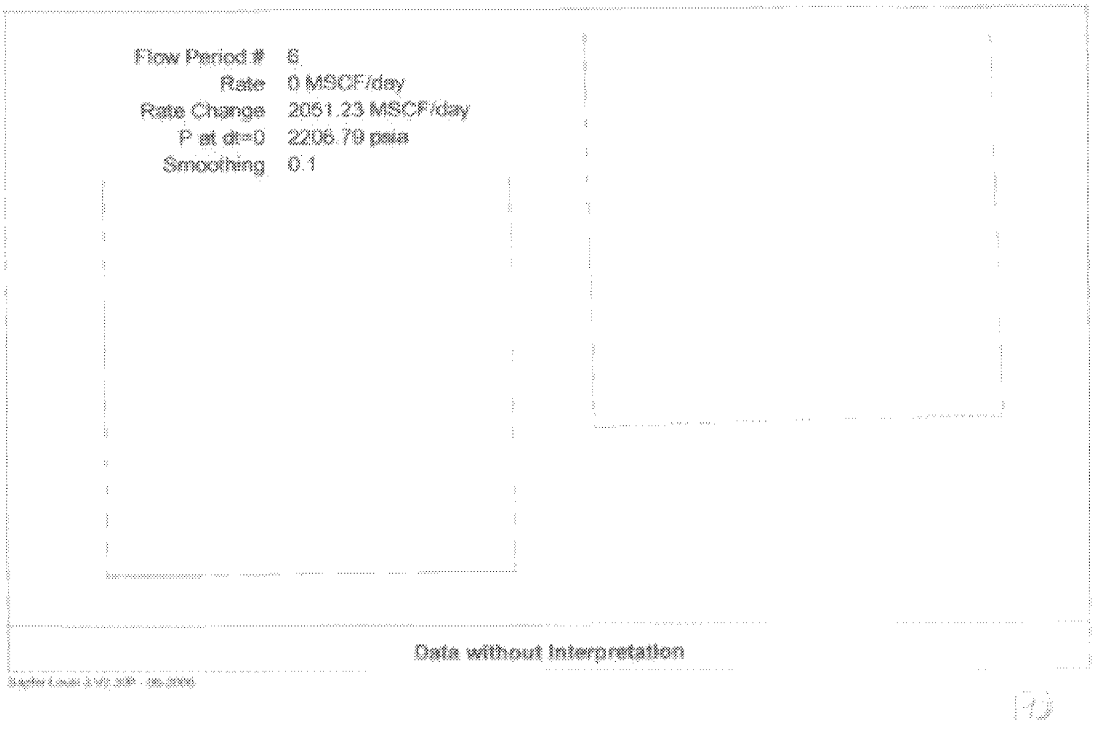

625_may2000 : History
Company
Field
Well
Test
2210
2200
2190
2180
2170
0
-2051.23
10
20
30
40
50
60
70
80
90
100
P (psia) & Q (MSCF/day) versus T [hr]
Flow Period # 6
Rate 0 MSCF/day
Rate Change 2051.23 MSCF/day
P at dt=0 2206.79 psia
Data without interpretation

Appendix I

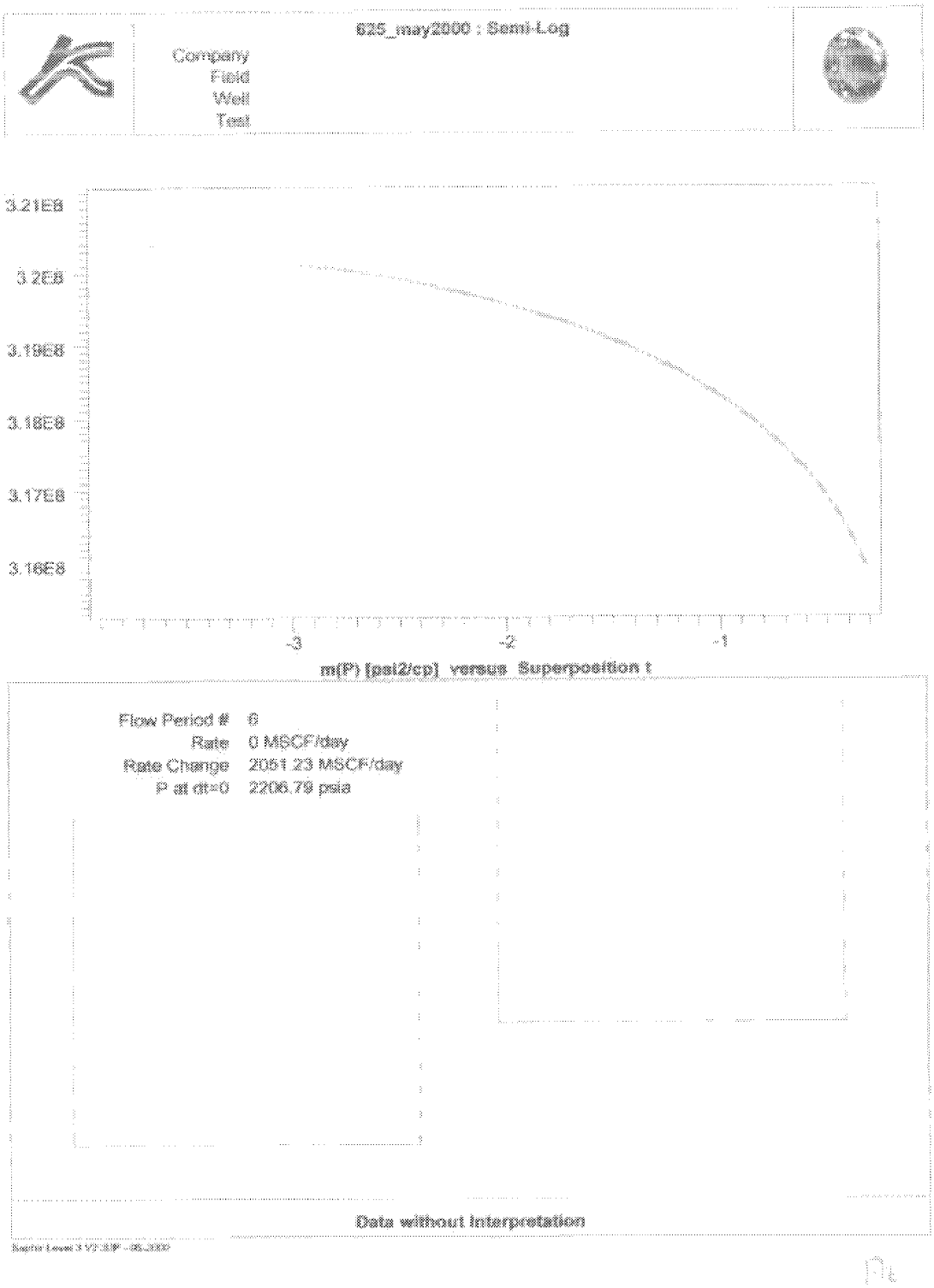

625_may2000 : Flexible
Company
Field
Well
Test
2200
2190
0
10
20
30
P versus dt
Data without interpretation

Appendix I

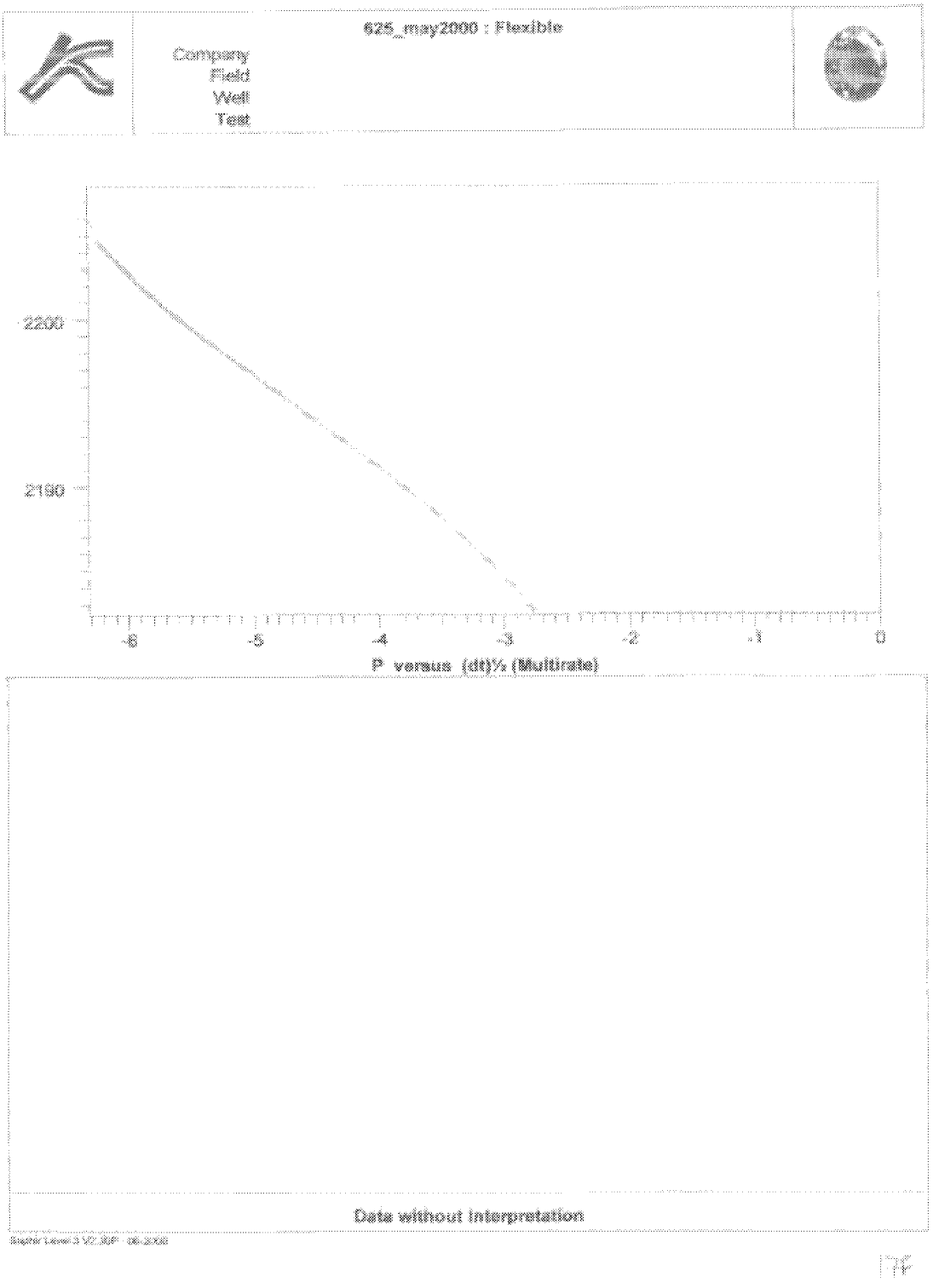

625_may2000 : Log-Log
Company
Field
Well
Test
10 7
10 6
10 5
10 -3
10 -2
0.1
1
10
100
10 3
10 4
dm(P) [psi2/cp] versus dt [hr]


Flow Period # 6
Rate 0 MSCF/day
Rate Change 2051.23 MSCF/day
P at dt=0 2206.70 psia
Smoothing 0.1
Data without Interpretation

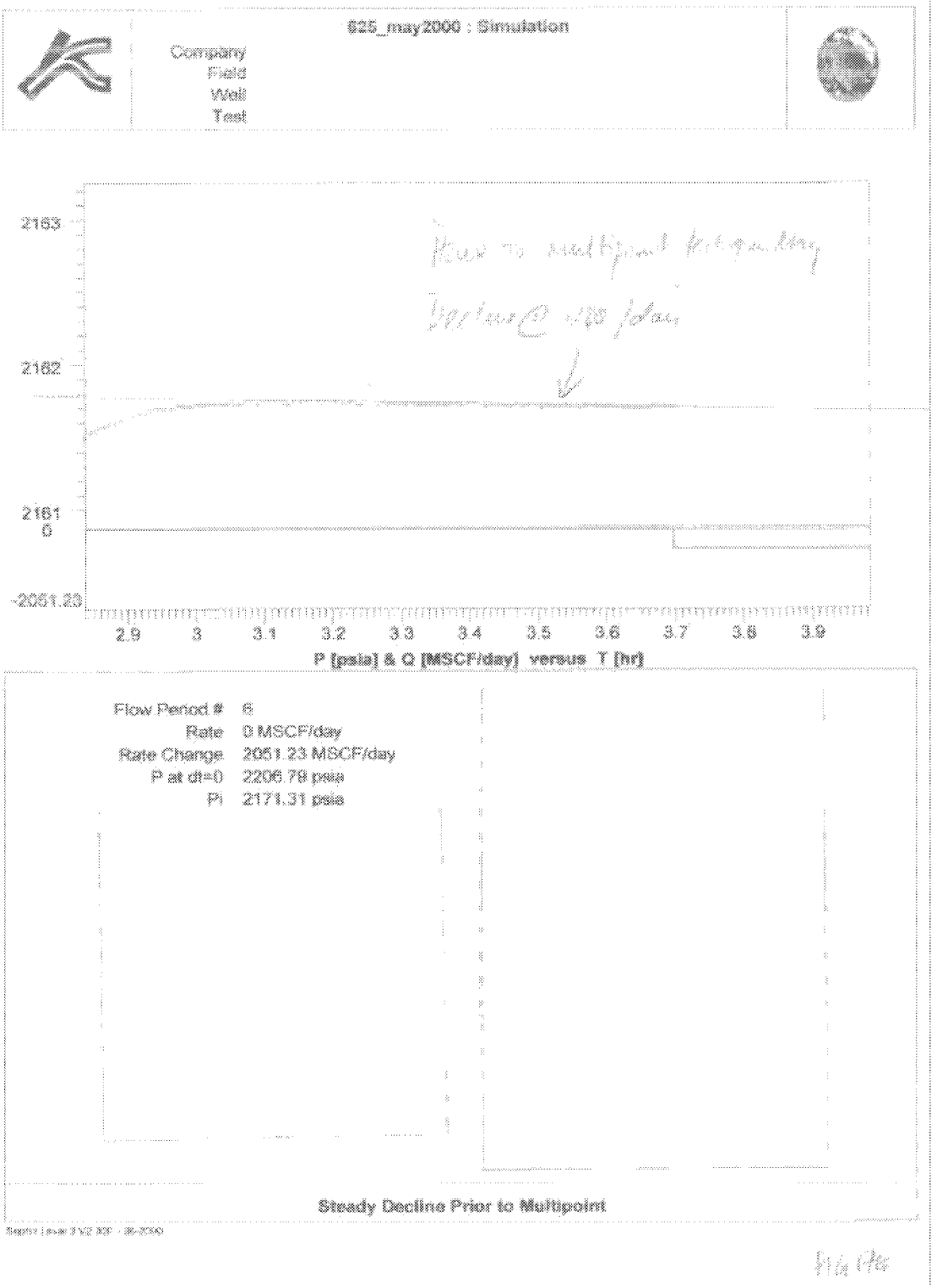
Appendix I


625_may2000 : Semi-Log
Company
Field
Well
Test
3.21E8
3.2E8
3.19E8
3.18E8
3.17E8
3.16E8
-3
-2
-1
m(P) [psi2/cp] versus Superposition t
Flow Period # 6
Rate 0 MSCF/day
Rate Change 2051.23 MSCF/day
P at dt=0 2206.79 psia
Data without interpretation

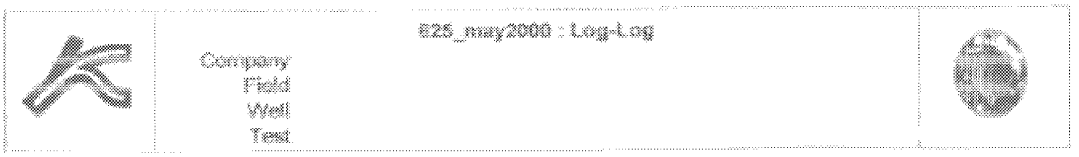
Appendix I

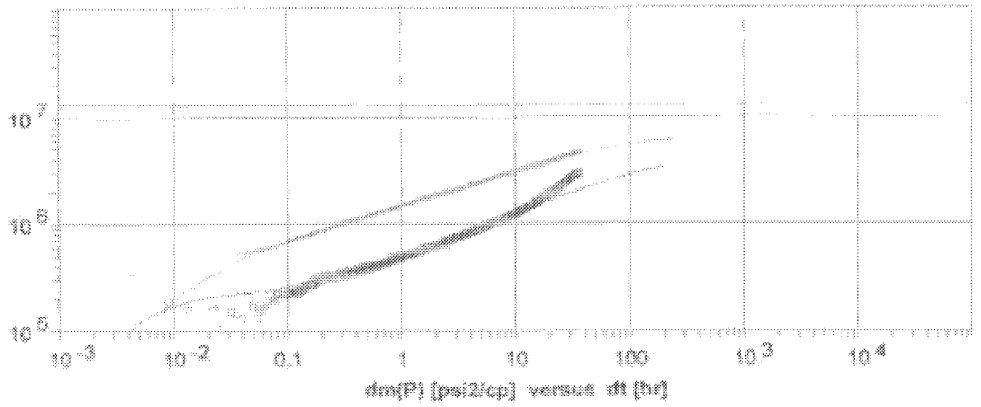

625_may2000 : Flexible
Company
Field
Well
Test
2200
2190
-6
-5
-4
-3
-2
-1
0
P versus (dt)½ (Multirate)
Data without interpretation

Appendix I


625_may2000 : Simulation
Company
Field
Well
Test
2163
2162
2161
0
-2051.23
2.9
3
3.1
3.2
3.3
3.4
3.5
3.6
3.7
3.8
3.9
P [psia] & Q [MSCF/day] versus T [hr]
Flow Period # 6
Rate 0 MSCF/day
Rate Change 2051.23 MSCF/day
P at dt=0 2206.78 psia
Pi 2171.31 psia
Steady Decline Prior to Multipoint

Appendix I





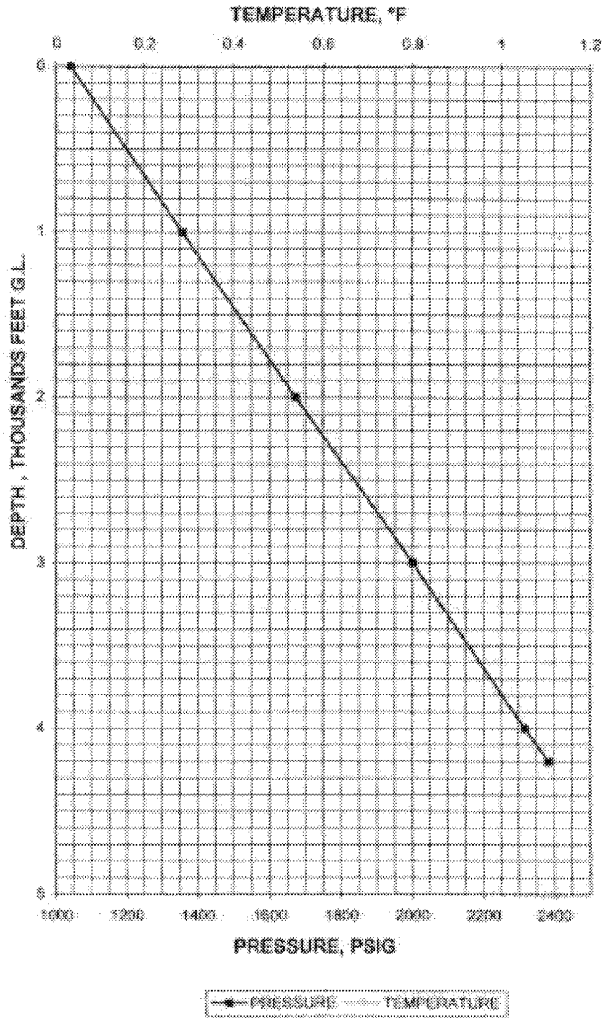
Flow Period #	8	RESERVOIR	Homogeneous
Rate	0 MSCF/day	BOUNDARY	Infinite
Rate Change	2051.23 MSCF/day	WELL	Horizontal well
P at dt=0	2206.79 psia	Storage C	5.83E-11 STB/psi
Smoothing	0.1	Skin factor	-0.062
Pi	2171.31 psia	Delta P Skin	-8.09625 psia
		h	90 ft
Time Match	5.03E9 (hr)-1	hw	937 ft
Pressure Match	3.95E-8 (psi2/cp)-1	zw	22.5 ft
		kr.h	64 md.ft
		kr	0.71 md
		kz/kr	25
		kz	17.8 md
		Top	sealing
		Bottom	sealing
		Mobility kr/mu	11.1
		Investig. R	116 ft
		Tested Volume	1085575 Barrels

Match for Horiz well and 90' thickness

ARC PRESSURE DATA INCORPORATED

WELL GRADIENT SHEET

COMPANY	PHILLIPS PETROLEUM CO.	LEASE	SOUTH COWDEN UNIT	WELL NO.	6-28H
FIELD		COUNTY	ECTOR	STATE	TX
FORMATION		SHUT IN DATE & TIME		HOURS SHUT IN	
TEST DATE	2/22/99	TIME	10:03	WELL STATUS	INJECTING
				JOB NUMBER	1964S



MEAS. DEPTH FEET G.L.	TRUE DEPTH FEET G.L.	TEMP. °F	PRESSURE PSIG	GRADIENT PSI/FT
0	0		1041.37	
1000	1000		1357.51	0.3161
2000	2000		1674.50	0.3170
3000	3000		2000.74	0.3262
4000	4000		2316.84	0.3161
4197	4197 R. D.		2382.76	0.3346

Elev. K.B. -	4943	G.L. -	
Pressure Datum			
Tubing	3 1/2"	Depth	4943'
S.N.	2.313"	Depth	4933'
Casing	7	Depth	
Perforations			
Total Depth	6244		
Casing Pressure	PACKER @ 4923'		
Tubing Pressure	1010 PMG		
Temp @	4197'	=	94.58°
Instrument No.	R-1		
Run By	MAX WHEELER		
Calculated By	HUB HAGLER		

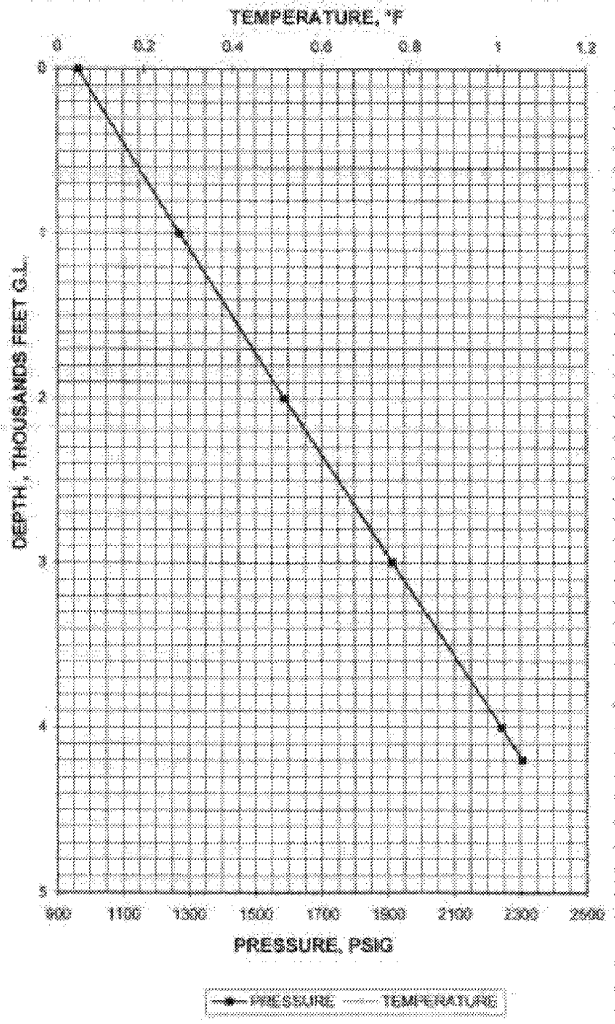
FIG19A

Appendix I

ARC PRESSURE DATA INCORPORATED

WELL GRADIENT SHEET

COMPANY	PHILLIPS PETROLEUM CO.	LEASE	SOUTH COMDEN UNIT	WELL NO.	6-25H
FIELD		COUNTY	ECTOR	STATE	TX
FORMATION		SHUT IN DATE & TIME	2/22/00 11:04	HOURS SHUT IN	120.16
TEST DATE	2/27/00	TIME	11:14	WELL STATUS	SHUT IN
				JOB NUMBER	19545



MEAS. DEPTH FEET G.L.	TRUE DEPTH FEET G.L.	TEMP. °F	PRESSURE PSIG	GRADIENT PSI/FT
0	0		965.85	
1000	1000		1273.69	0.3160
2000	2000		1588.88	0.3149
3000	3000		1912.76	0.3242
4000	4000		2242.96	0.3301
4197	4197 R. D.		2305.19	0.3163

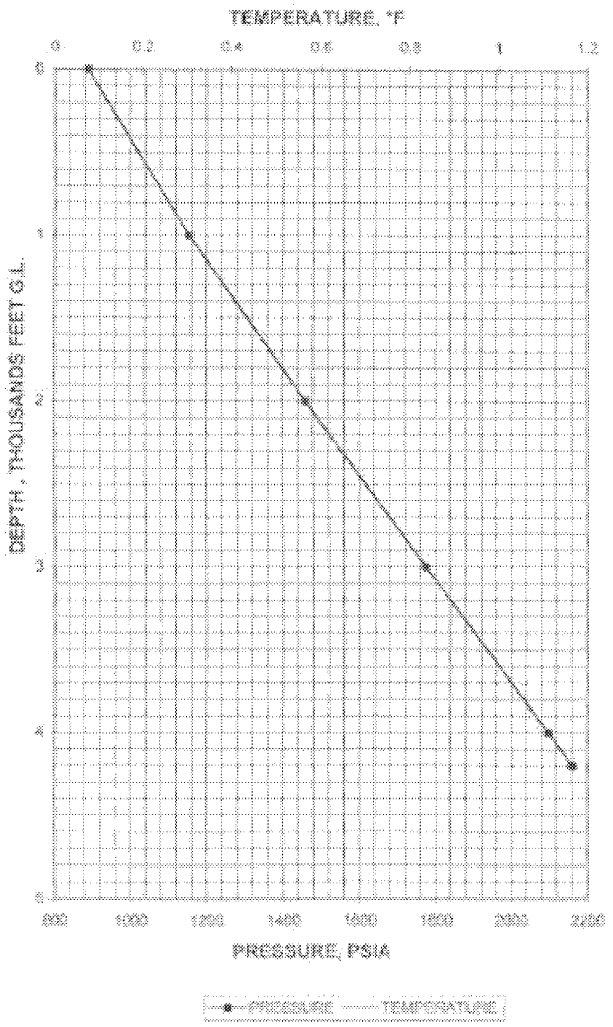
Elev. K.B. -	4943'	G.L. -	
Pressure Datum			
Tubing	3 1/2"	Depth	4943'
S.N.	2.313"	Depth	4933'
Casing	7	Depth	
Perforations			
Total Depth	6244		
Casing Pressure	PACKER @ 4923'		
Tubing Pressure	960		
Temp. @	4197'	=	93.04°
Instrument No.	P-1		
Ran By	MAX WHEELER		
Calculated By	HUB HADLER		

MB

ARC PRESSURE DATA INCORPORATED

WELL GRADIENT SHEET

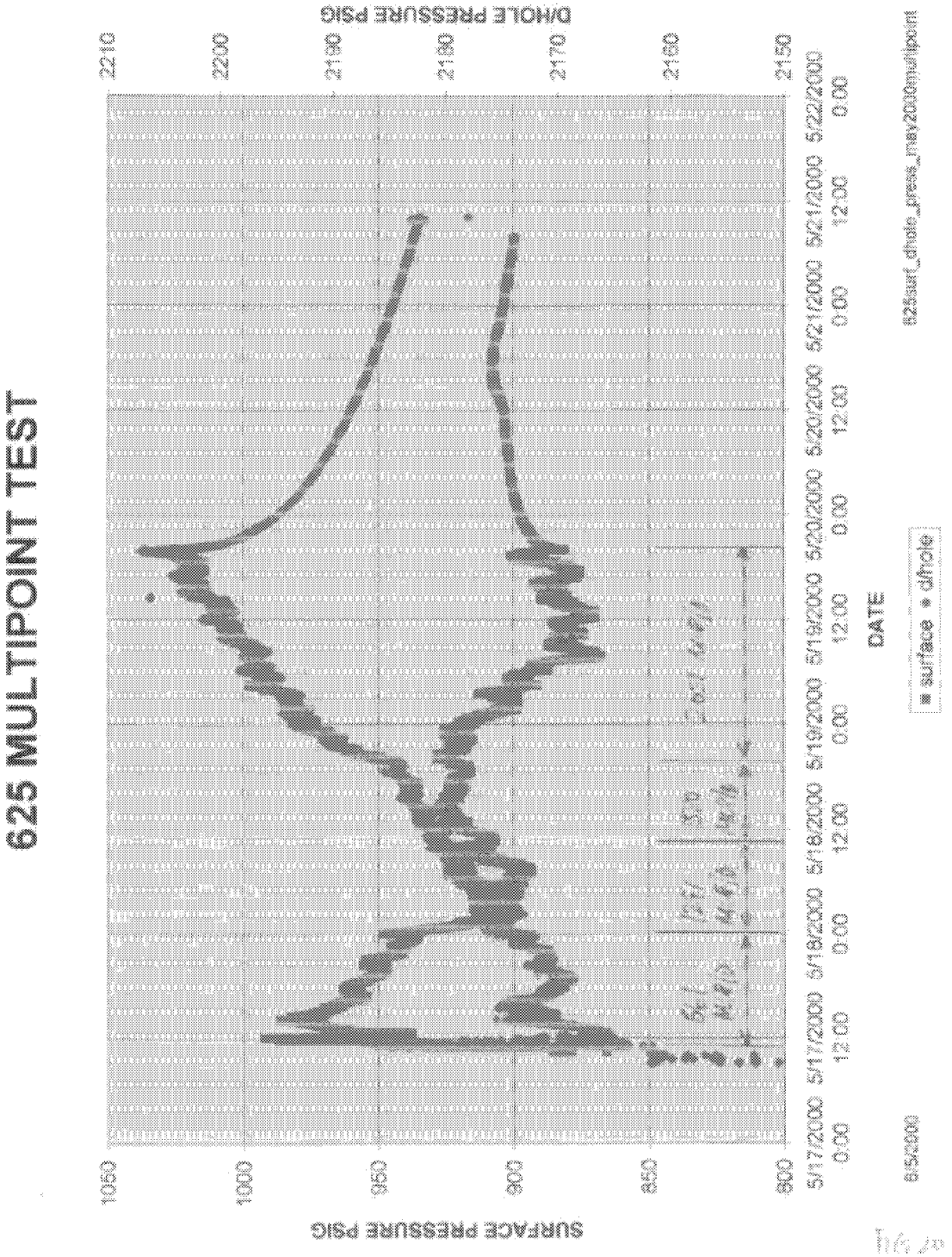
COMPANY	PHILLIPS PETROLEUM CO.	LEASE	SOUTH COWDEN UNIT	WELL NO	625-H
FIELD		COUNTY ECTOR		STATE	TX
FORMATION		SHUT IN DATE & TIME		HOURS SHUT IN	
TEST DATE	5/17/00	TIME 10:07	WELL STATUS SHUT IN	JOB NUMBER	19623A



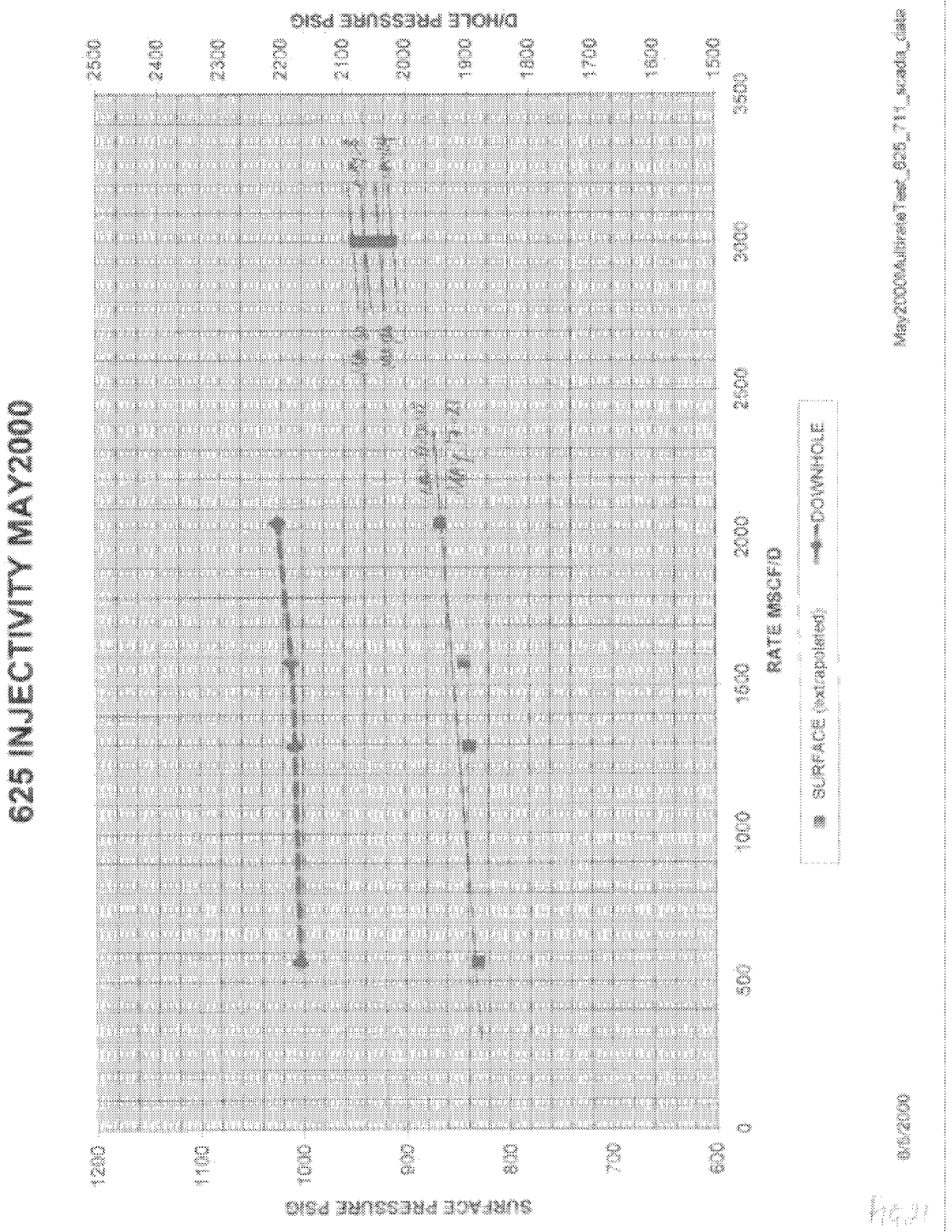
MEAS DEPTH FEET G.L.	TRUE DEPTH FEET G.L.	TEMP °F	PRESSURE PSIA	GRADIENT PSI/FT
0	0		888.31	
1900	1900		1165.47	0.2673
2900	2900		1459.12	0.3557
3900	3900		1774.91	0.3158
4900	4900		2097.73	0.3228
4198	4198 R. D.		2160.04	0.3702

Elev: K.B.		G.L.	
Pressure Datum			
Tubing	3 1/2"	Depth	4943
S.N.	2.313"	Depth	4933'
Casing	7"	Depth	
Perforations	@ 1/8" Cal		
Total Depth			
Casing Pressure	PACKER @4923'		
Tubing Pressure	677 DWG		
Temp. @	4148'		94°
Instrument No.	APG #4		
Run By	MAX WHEELER		
Calculated By	LAURI HADLEY		

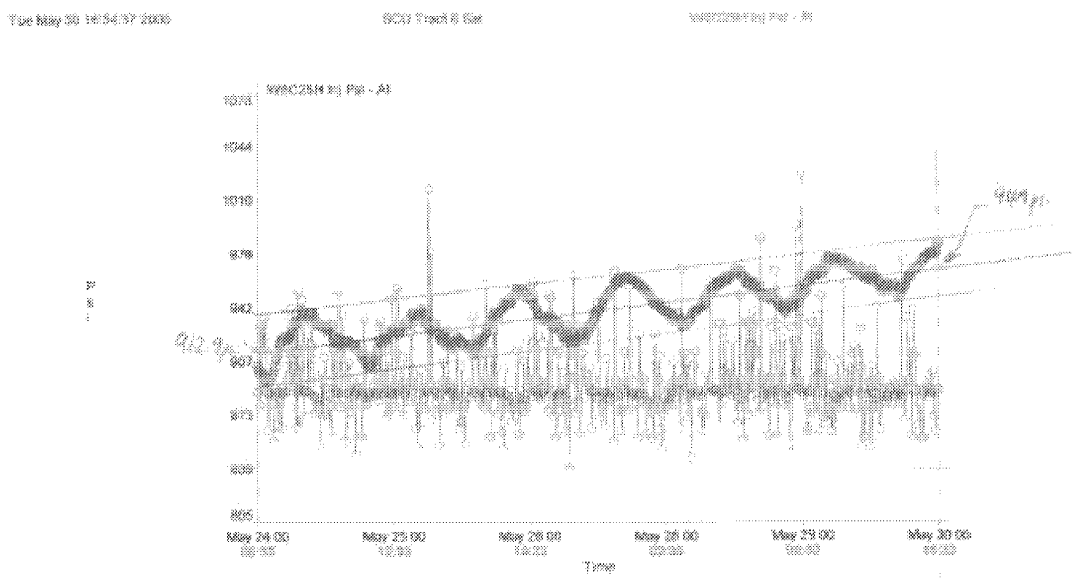
Appendix I


625 MULTIPOINT TEST
SURFACE PRESSURE PSIG
DHOLE PRESSURE PSIG
DATE
surface
dhole
625surf_dhole_press_max2030multipoint
8/5/2000

Appendix I


625 INJECTIVITY MAY2000
D/HOLE PRESSURE PSIG
2500
2400
2300
2200
2100
2000
1900
1800
1700
1600
1500
3500
3000
2500
2000
1500
1000
500
0
RATE MSCF/D
SURFACE (extrapolated)
DOWNHOLE
SURFACE PRESSURE PSIG
1200
1100
1000
900
800
700
600
May2000AllInOneTest_625_711_scada_data
05/2000

Appendix I



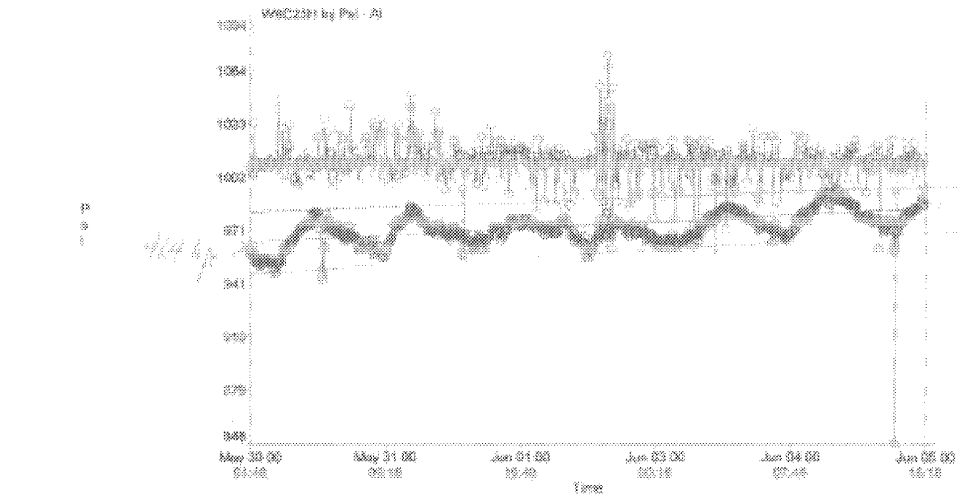
pressure/day = $\frac{949.25 - 912.9}{6.46 \text{ days}}$

= 5.63 psi/day.

	ITHP (psi)
May 24	918
May 26	924
May 28	936
May 30	947

FIG 2.9

Appendix I



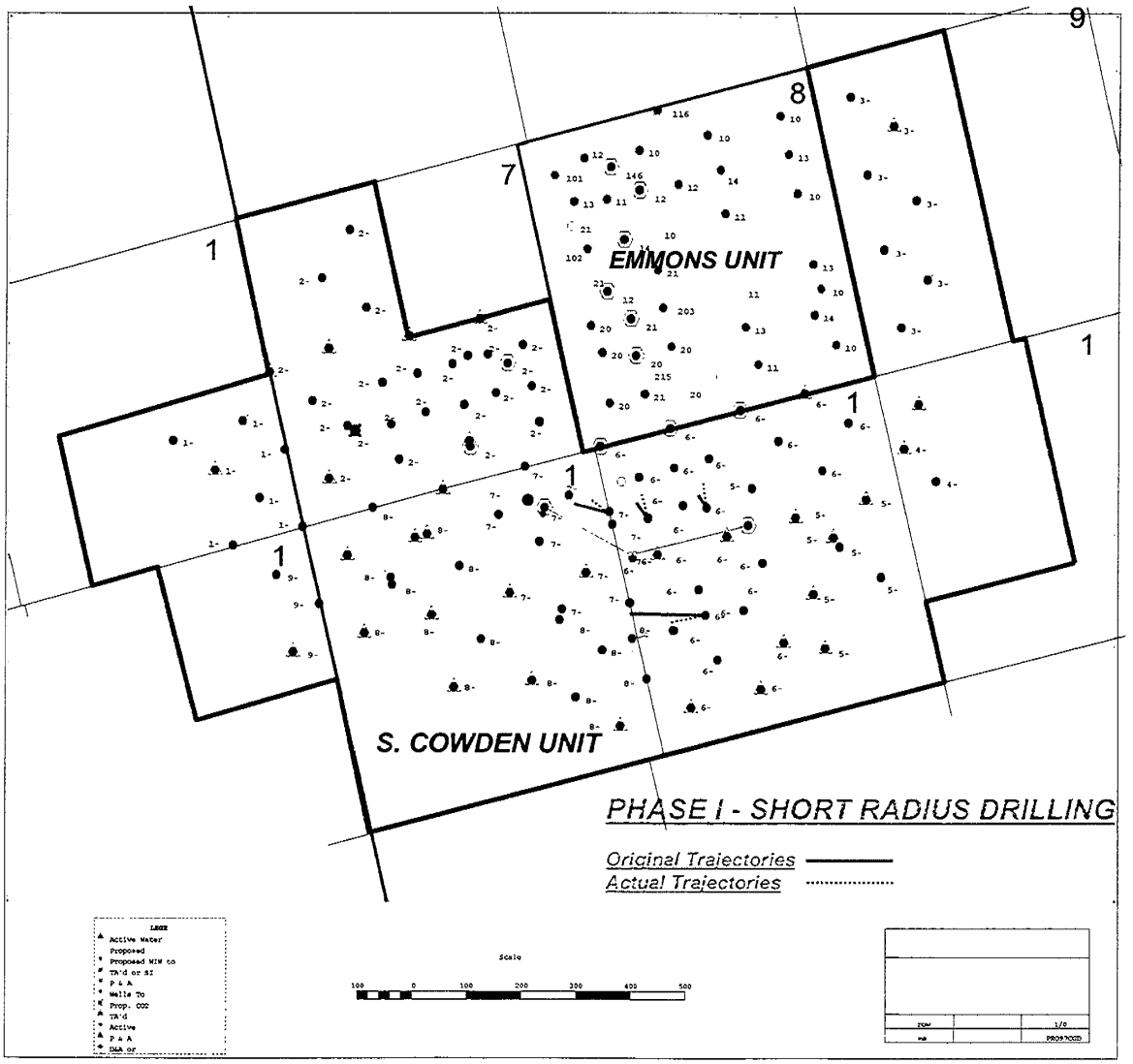
APPENDIX J

Redevelopment Phase 1 Results

Phase 1 Redevelopment Operations

Summary

Phase I was completed in May 2000. It was deemed a success in regard to finding suitable/cost-effective technology for drilling horizontal laterals and finding a technique that could sustain long-term productivity from the upper layers of the San Andres reservoir. Four existing vertical producing wells 7-13, 6-23, 6-20 and 6-22 were isolated from their existing completions and side-tracked with horizontal laterals into the upper layers of the San Andres. Overall average offtake rates for the four wells increased by a factor of 12 during the first four months after completion of Phase 1.



Several weeks of preparation work were involved prior to commencing Phase 1 activities. A Rotary Steerable System was chosen initially as the lateral drilling technique. Phillips worked closely with the drilling contractor and also additional service companies to resolve as many up front and anticipated operational issues prior to commencing Phase 1.

Three out of the four wells required conformance work to seal up the existing vertical well. Injection logs revealed behind pipe and micro annulus tendencies. A combination of Flocheck and foamed cement proved effective at resolving these issues.

The majority of carbon dioxide (CO_2) injection was shut down in the lease prior to commencing Phase 1. During this time downhole pressure gauges were installed in the two horizontal CO_2 injectors. The analysis revealed that 6C25H injectivity had essentially not changed since starting CO_2 injection. For the 7C11H, the horizontal injector with a known "toe-fracture", the analysis revealed the fracture was still present and had become easier to initiate since the last injection test performed in 1996. The analysis was also used to provide fracture dimensions for conformance work planned during Phase 2 Redevelopment.

A summary of the time breakdown and lateral drilling costs are provided below.

DRILLING/COMPLETION

WELL	DAYS							DEPARTURE FT			AZIMUTH degrees			COMPLETION COST			TOTAL COSTS		
	PREP	PILOT&	LATERAL	COMPL'N	TOTAL	TOTAL	SUCCESS	PRIOR	POST	SUCCESS	PRIOR	POST	SUCCESS	PRIOR	POST*	SUCCESS	PRIOR	POST*	SUCCESS
	excl con	CURVE			ACTUAL	PRIOR	Y/N			Y/N			Y/N			Y/N			Y/N
713	5	6.1	9	1	21.1	<10	N	630	590	Y	290	282	Y	10 to 12	16.3	N	<150	304	N
623	6	4.3	7.2	1	18.5	<10	N	630	300	N	337	337	Y	10 to 12	13	N	<150	276	N
620	7	6	6	1	20.0	<10	N	700	480	N	0	330	N	10 to 12	9.1	Y	<150	248	N
622	2	2.8	2.3	1	8.0	<10	Y	700	1500	Y	265	263	Y		28.3			197	
622(700')**	2	2.8	1.0	1	6.8	<10	Y	700	700	Y	265	263	Y	10 to 12	10	Y	<150	135	Y

** Costs from DIMS reports*
*** estimated after drilling 700' of lateral*

WELL	COMMENTS
713	ORIGINAL TORCH ROTARY STEERABLE SYSTEM
623	AS ABOVE, w/ REDUCED SURVEYING .. Poor Actual vs Prognosed control. Poor Penetration rates.
620	CURVE - AS ABOVE, LATERAL w/ MUD MOTOR .. Poor directional control. Poor Penetration rates curve section.
622	SCIENTIFIC DRILLING SYSTEM (WHIPSTOCK/MUD MOTOR) .. Good penetration curve and esp lateral. Note 622 important well to demonstrate effective conformance treatment with known severe lower zone communication.

Rotary Steerable Problems:
1) Timing Preparation work
2) Lack of directional control
3) Penetration Rates Curve/Lateral
4) Twisting Off and Fishing.

Lateral drilling commenced with 7-13 lateral in early March 2000. The lateral took just over 21 days to complete compared to 10 days or less originally anticipated. As a result, drilling costs for the well were higher than anticipated. Prior to starting Phase 1 work costs for each well was anticipated to be less than $150K (if no serious conformance issues were encountered).

Preparation times, curve drilling time and straight section drilling all took longer than anticipated. This was related to poorer curve/straight section penetration rates, frequent drill-pipe "twist-off" with the resulting fishing operations, and poor directional stability resulting in changes in drll-pipe to correct trajectories.

The heated acid stimulation, using coiled tubing and hydrablast tool, went without incident, and proved operationally easy to accomplish on this and subsequent wells.

6-23 was the next well in the program. Several changes were made to improve drilling times. Even with changes no dramatic improvement of penetration rates were realized. The well took a total of 18.5 days to drill to a 300-foot (ft) departure from the existing well. The fundamental problem was the poor penetration rates and time taken for preparation. Preparation work involved sectioning the casing, setting a cement plug and dressing the plug off to a kick off point.

6-20 was the third well in the program. The drilling contractor had agreed the previous penetration rates were not acceptable, and agreed to use a downhole motor system for the straight section. This, however, had poor directional control and required a trajectory change using the curved assembly from the rotary steerable system. The same fundamental problem of poor preparation and curved drilling duration still existed using this revised system, even though somewhat improved penetration rates had been realized with a downhole motor system in the straight section.

For the final well a different approach was taken using an alternate contractor's system. This had been used successfully on offset leases. The system was a four-stage process. Once the well is prepared a whipstock installed, the casing is milled, and the curved section drilled with a mud motor. Finally, the lateral section is drilled with a mud motor. Surveying is performed using a measurement while drilling (MWD) tool, typically taking 15 seconds to survey. Any corrections to direction/trajectory are performed downhole.

The new technique proved a success with 700 ft departure drilled after 6 days from the commencement of operations. As penetration rates were so good the contractor was asked to extend the length of the well out to 1500'. This was completed after an extra day and a half. If the well had been completed with 700' the total cost was e stimated under $150k. The drilling technique had therefore proven a 700' lateral could be drilled cost effectively at the lease, and the team was confident in applying the same technique for Phase 2 laterals.

Production monitoring through April 2000 to October 2000 was employed to evaluate the success of laterals to improve offtake from the lease.

7-13 vertical well, with a cased and perforated completion, produced at fluid rates of 13 barrels fluid per day (bf/d) prior to the lateral drilling. The lateral averaged 181 bf/d through the monitoring period with an average oil production of 75 barrels oil per day (bo/d). This was an average 13-fold increase in productivity. Little or no productivity loss was observed.

6-23 vertical well produced at fluid rates of 78 bf/d prior to the lateral drilling. The lateral averaged 311 bf/d through the monitoring period with CO_2 response evident at the end. This was an average 4-fold increase in productivity. Little or no productivity loss was observed. This well was not drilled as anticipated with only 300 ft departure against the 630 ft planned, but still managed an acceptable productivity improvement.

6-20 vertical well produced at fluid rates of 56 bf/d prior to the lateral drilling. The lateral averaged 292 bf/d through the monitoring period with oil rates increasing to 90 bo/d at the

end. This was an average 5-fold increase in productivity. Little or no productivity loss was observed.

6-22 vertical well produced at fluid rates of 56 bf/d prior to the lateral drilling. The lateral averaged 1485 bf/d through the monitoring period with no CO_2 response seen. The well was anticipated to take some time to respond to CO_2 injection due to the physical distance to the nearest CO_2 injector. This was an average 25-fold increase in productivity. Little or no productivity loss was observed.

Overall average offtake rates for the four wells increased by a factor of 12 during the first 4 months after completion of Phase 1.

The effect on the total lease was to increase offtake by an average of 27%, accelerating the lease productivity and the reduction in reservoir pressure. Total lease oil rates increased from a low of 400 bo/d at the beginning of Phase 1, to a high of 575 bo/d at the end of the monitoring period.

Preparation for Phase 1 and Description of Rotary Steerable System

Torch lateral drilling was identified in 1999 as a suitable contractor for the work required at South Cowden. Their bid estimates suggested the work would be completed using a rotary steerable system at the best price. Activities prior to the start of drilling were related to preparation work for Phase I, followed by project initiation on March 6.

The Torch technique involves sectioning the casing, setting a cement plug and finally drilling the curved and straight sections of the lateral. The rotary steerable system uses a titanium drillpipe to bend through the short radius of the curved section. The remaining drillpipe to surface is conventional. Running a survey tool periodically through the drillpipe performed surveying.

More detail regarding the Rotary Steerable System is contained in the Appendix Original Development and Redevelopment Review.

Both the curved and straight sections are drilled using a "set angle". Once the radius of curvature is set the system will maintain a certain curvature. If the survey tools reveal the well is deviating from the target, the drill string is removed, a revised angle set at surface and drillpipe re-run.

Preparation work centered on ensuring the contractor had all information necessary to plan and execute the lateral drilling. Phillips worked closely with the contractor to determine several operational problems that may occur while lateral drilling to pre-plan any back up procedures.

Activities related to identifying/resolving conformance issues for the existing vertical Phase I wells, from which the laterals would be drilled were evaluated. The use of injection logs and

use of polymer gels/foamed cement were identified, in collaboration with Halliburton, as the appropriate techniques for identifying/resolving these concerns.

Preparation work also involved identifying a suitable stimulation technique for the lateral section. The final technique developed used a heated acid treatment that is injected below fracture pressure to wash and, to some extent, matrix acidize the near lateral area. Coiled tubing and the use of Halliburton's hydrablast tool would be used to inject acid along the open hole lateral length from the toe to heel. Heated acid was found to be more reactive to upper layer San Andres rock, based on laboratory core tests. This is discussed in the Appendix Original Development and Redevelopment Review.

Suitable logging tools were screened for identifying fractures that may beencountered while drilling. The short radius nature of the designs, however, did not allow for any of the better fracture identifying tools such as Halliburton's CAST-V log or a conventional sonic log.

A "Pre-spud" meeting was held with all contractors in early March 2000 to introduce all contractors involved with their objective, discuss the program for the wells and to improve communication between the various companies involved.

Conformance

Preparation work centered on finding suitable techniques for sealing up communication between upper and lower layers.

Cement bond logs (CBL) were planned for each well to determine if cement integrity was an issue especially for kick off points for laterals. Also injection logs were planned to determine if conformance issues were apparent in each well.

Well 7-13 was not identified as a well with serious conformance issues, after running the injection log. Cement integrity was good at the kick of point.

Well 6-23 injection log identified a channel/communication path to lower layers and also a possible micro annulus through the cement to the Grayburg zone above the San Andres. Cement was good at kick off point. The conformance work involved the use of Halliburton's flowcheck to seal up any micro fractures that may exist in the near well area followed by a foamed cement squeeze to seal any behind casing channels. The work went well with no problems.

Well 6-20 injection log also identified communication paths behind pipe down to the lower layers and also up to the Grayburg. Also of note was a casing restriction found in the well at perforation depth. The temperature log indicated a dramatic cooling effect, which was likely to have been caused by CO_2 production in this interval. The CO_2 must have therefore degraded the casing over time and a restriction found at this depth. Cement integrity was good at kick off point.

Well 6-20 injection log identified communication paths behind pipe down to lower layers and also up to the Grayburg interval. A foamed cement squeeze was recommended to resolve the conformance issues and the job was performed in early April.

Well 6-22 injection log identified communication paths behind pipe down to the lower layers. A foamed cement squeeze was recommended to resolve the conformance issues. The job was performed successfully in May prior to lateral drilling. This well had previously been thought of as having severe upper-lower communication due to high CO_2 rates observed from production tests in 1998/1999. Because of the severity of the communication, at that time, a plug was set to prevent production from zones below the F zone. This was, therefore, an important well to demonstrate severe conformance issues can be resolved. Conformance work for Phase II leaseline wells, where severe conformance issues was thought to exist, were dependent on 6-22 demonstrating successful techniques to resolve severe behind pipe communication.

CO_2 Injection Wells

As part of the Phase I drilling program the contractor advised shutting in all nearby CO_2 injection to lower reservoir pressure, and prevent any high-pressure direct communication that may exist between injectors and laterals.

To take advantage of shutting in the wells downhole gauges were placed in both 6C25H and 7C11H horizontal CO_2 injection wells on February 21. The objective was to determine any injectivity differences when compared to downhole testing performed in 1996. Additional downhole testing took place in May when the wells were started on injection.

The February tests took place as the wells were shut in to allow cessation of CO_2 injection for lateral drilling. The second tests took place as the wells started injecting again in early May 2000. The first tests were simple fall off tests; the second tests were multirate injection tests followed by a fall off.

The analysis proved useful for understanding the characteristics of both wells. In particular the test on 7C11H revealed the fracture present at the wells' toe was confirmed as a pressure induced fracture that currently appears to be getting easier to inject into as more CO_2 is injected in the well.

The fracture dimensions at 7C11H are dependent on the thickness used for analysis, but can be estimated as:

Xf (half-length) = 32 ft, using an infinite conductivity model and 280'thickness.
Xf (half-length) = 70 ft, using an infinite conductivity model and 60'thickness.
The closure pressure is estimated at 1988 pounds per square inch gauged (psig).

These results could be used for potential volumes required for conformance work.

Also of note was 6C25H injectivity compared to 7C11H. Even though 7C11H appears to be in contact with an infinite conductivity fracture it appears to have a much lower injectivity

index (at low rates). 7C11H averages 9.9 thousand standard cubic feet per day, per pound per square inch (MSCF/D/psi) compared to 6C25H with 45 MSCF/D/psi. Which suggests if the conformance is resolved at 7C11H, a horizontal well would have improved injectivity for the area around 7-01/7-13.

6C25H analysis suggests either vertical communication is larger than currently modelled or the distance is less to the impermeable boundary, above the horizontal well (top of San Andres). Therefore there may be sections of the well with rapid vertical communication capabilities (such as a karstic infill area, or highly burrowed sections), or alternatively, the top of the E zone may be acting as a permeability barrier.

More details of the 7C11H and 6C25H analysis are included in the Appendices.

Also plans were laid to start producing back the leaseline wells between Emmons and South Cowden Unit (SCU) to lower overall reservoir pressure in this area. The three wells 6-26, 6-27 and 6-28 were placed on production during early June, after obtaining regulatory approval.

Lateral Drilling Operations

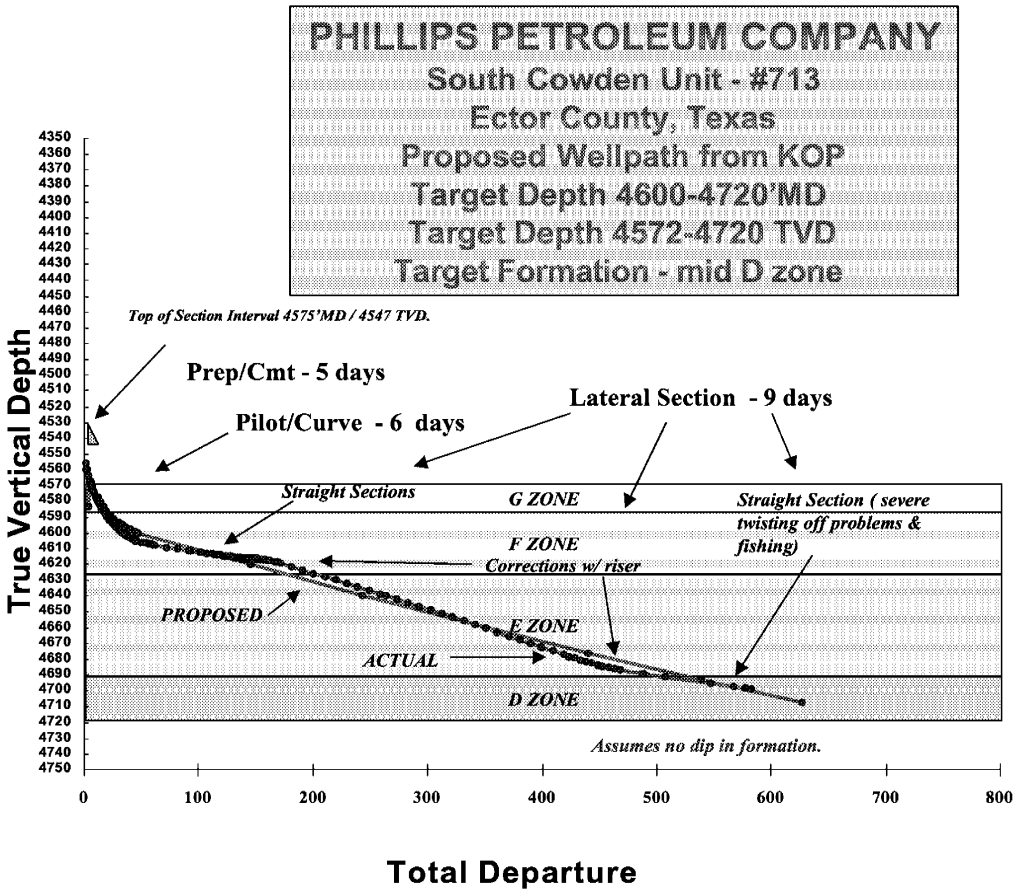
7-13

Well 7-13 was the first well in the program. Work commenced March 6 with the sectioning of the casing. The sectioning and cement plugging were complete by March 10. When drilling commenced slow penetration rates were observed while drilling the anhydrite section above the San Andres, near the kick off point. The curved section took 4 days to complete and was finished March 16.

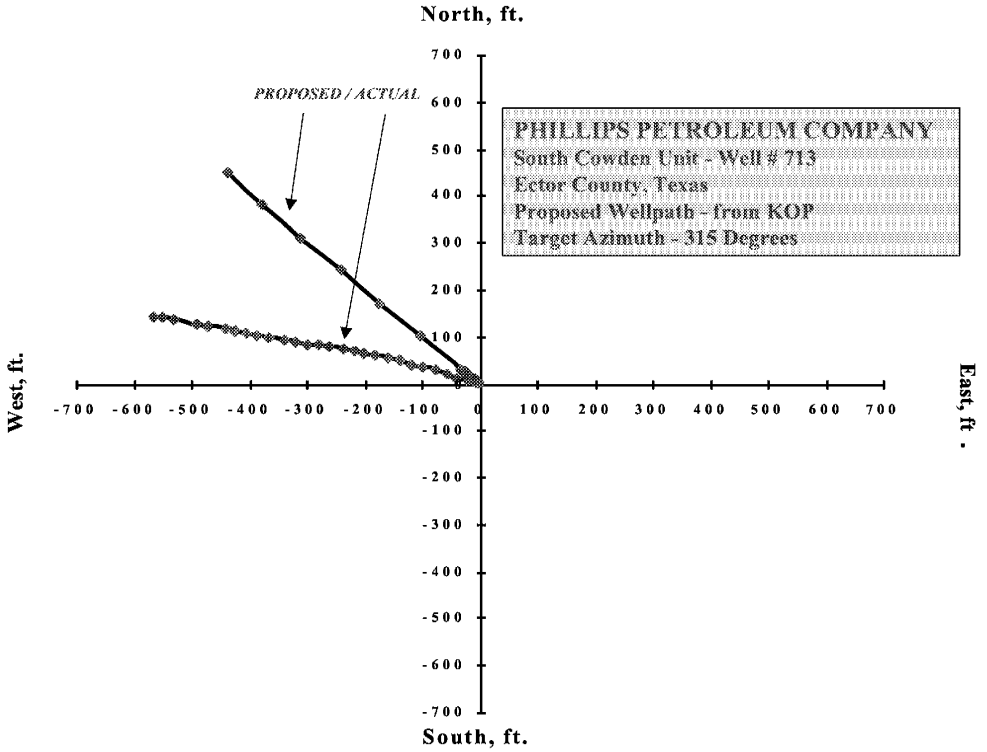
Well 7-13 "straight section" proved slow progress due mainly to fishing operations caused by drillpipe "twist off". There were delays due to deviation corrections required to keep the well on target and also some delays due to severe weather. By the end of March the well had been drilled to within 60' of the prognosed lateral departure, and left to be completed.

As a result of the slower "straight section" progress than anticipated, the use of centralizers were recommended for the next well to keep the titanium drillpipe from scraping against the casing while drilling. As a result of the curve sections slow progress in the interval above the San Andres, it was agreed to lower the kick off point by 10' for the remaining wells to reduce drill time in this interval. It was also agreed to use a second rig to prepare the wells (i.e. the casing sectioning and the setting of the cement plug), this would prevent the lateral drilling rig from waiting on cement plug to set.

The heated acid treatment was performed at Well 7-13, and proved operationally very successful. The configuration at surface was to heat the water to 160° Fahrenheit (F) and commingle with 28% hydrochloric (HCl) acid at surface conditions. This would dilute the injection stream to 15% HCl acid at a temperature at approximately 130° F at surface. The coiled tubing Hydrablast tool moved throughout the lateral section with no problems.


PHILLIPS PETROLEUM COMPANY
South Cowden Unit - #713
Ector County, Texas
Proposed Wellpath from KOP
Target Depth 4600-4720'MD
Target Depth 4572-4720 TVD
Target Formation - mid D zone
Top of Section Interval 4575'MD / 4547 TVD.
Prep/Cmt - 5 days
Pilot/Curve - 6 days
Lateral Section - 9 days
Straight Sections
G ZONE
Straight Section (severe twisting off problems & fishing)
F ZONE
Corrections w/ riser
PROPOSED
E ZONE
ACTUAL
D ZONE
Assumes no dip in formation.
True Vertical Depth
4350 4360 4370 4380 4390 4400 4410 4420 4430 4440 4450 4460 4470 4480 4490 4500 4510 4520 4530 4540 4550 4560 4570 4580 4590 4600 4610 4620 4630 4640 4650 4660 4670 4680 4690 4700 4710 4720 4730 4740 4750
0 100 200 300 400 500 600 700 800
Total Departure

Appendix J



6-23

Well 6-23 was the next well in the program. The well was prepared (logged/conformance work / sectioning / cementing plug set) with the second workover rig by March 23. The lateral rig moved to 6-23 on March 30. The curved section was finished at 4650' measured depth (MD) and the curve was widened to 4.75". The lateral was drilled to 4712' MD, at which point the well "twisted off" in the 2-1/16" tubing in the curved section. All fish was recovered and drilling continued to 4748' MD. It was found that incorrect thread protectors caused the restriction in drillpipe. This meant the contractor was unable to survey and drilling continued "blind" to a measured drill depth of 4865' MD.

At this depth the drillpipe was pulled out of hole (POOH), and a survey finally run. The well was deeper than anticipated, near bottom of E zone. The well path was therefore corrected with the curve assembly and total depth (TD) drilled with the "straight" section" to 4900' by April 10, where it twisted off at the crossover. After three days fishing, the drillpipe was retrieved but the well was not continued to its, due to reaching its Authority for Expenditure (AFE) limit. It was finally heat acid treated on coiled tubing on April 19 with the second workover rig.

After observing both 7-13 and 6-23's poor penetration rates and fishing issues, Phillips agreed with the contractor to concentrate on the next well 6-20 using an alternative method of drilling.

Well 6-23 was a disappointment because:

The contractor mistakenly ran Precision Hydril thread (PH-6) tubing, instead of titanium pipe, in the bottom section of drillpipe. The PH-6 tubing twisted off.

Incorrect thread connectors in the drill pipe prevented surveying and resulted in well being lower in formation than required.

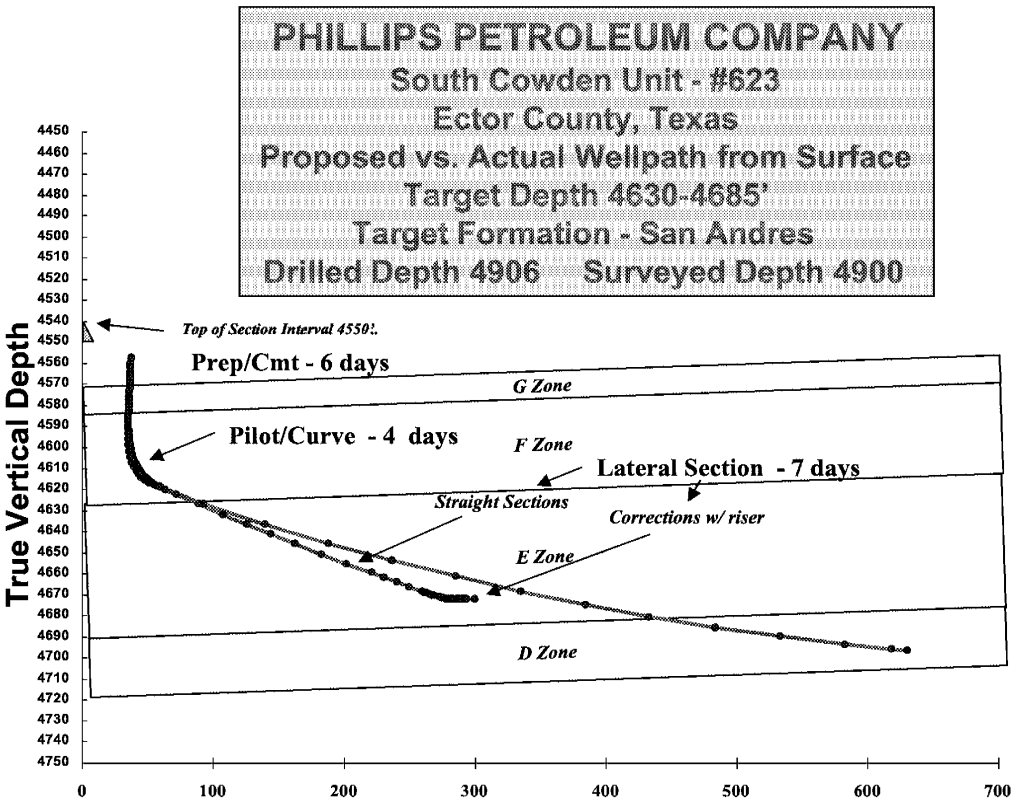
Twisted off at the crossover, which is somewhere that had not twisted off in 7-13, and proved difficult to fish.

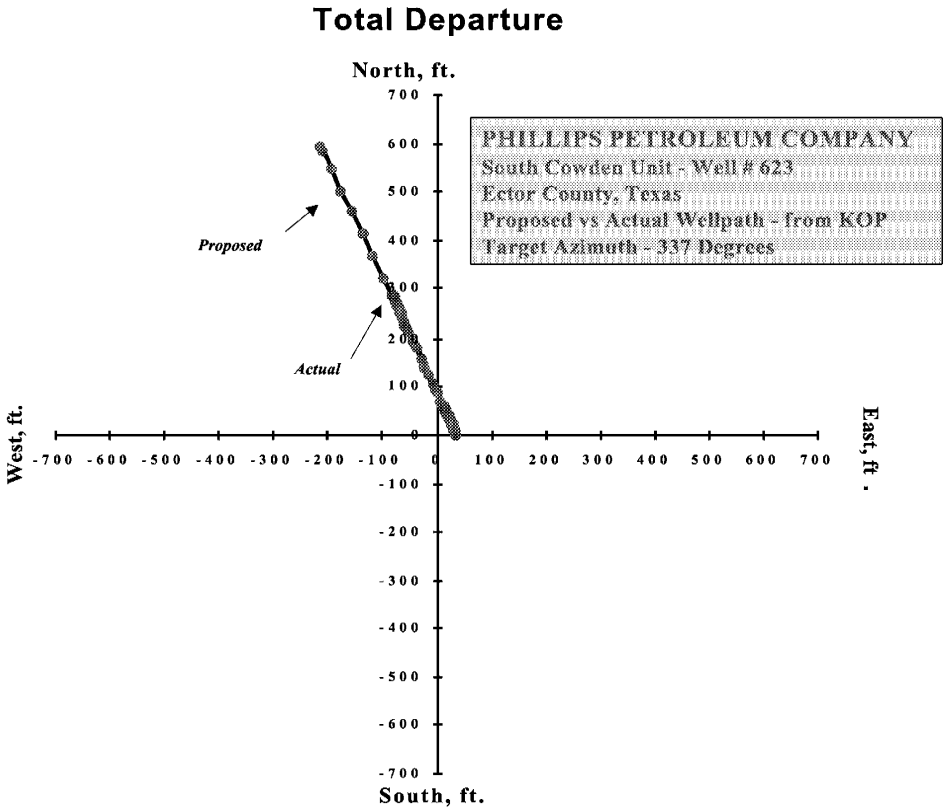
The lateral was not completed as proposed. Only 300' departure compared to the proposed 630'.

Simulation model suggested the extra 330' could have increased long-term recovery.

The plan for 6-23 was to leave it "as is" and return to this well at a later date and finish the remaining 300', if required.

As a result of poor curved/straight section performance, Phillips and the contractor discussed alternative options for the next well. These included running an alternative bit "Star35" for the curved section, while still using the rotary steerable system. It was thought this would have less directional control but would improve penetration rates. Also the contractor planned to use a mud motor system to drill the "straight" lateral section. This would enable the short radius curved section to be drilled with the Torch system and the lateral with the mud motor. The mud motor system would still use the Torch surveying tools, so no measurement while drilling (MWD) devices were used.


PHILLIPS PETROLEUM COMPANY
South Cowden Unit - #623
Ector County, Texas
Proposed vs. Actual Wellpath from Surface
Target Depth 4630-4685'
Target Formation - San Andres
Drilled Depth 4906 Surveyed Depth 4900
True Vertical Depth
Top of Section Interval 4550'.
Prep/Cmt - 6 days
G Zone
Pilot/Curve - 4 days
F Zone
Lateral Section - 7 days
Straight Sections
Corrections w/ riser
E Zone
D Zone


Total Departure
North, ft.
South, ft.
West, ft.
East, ft .
Proposed
Actual
PHILLIPS PETROLEUM COMPANY
South Cowden Unit - Well # 623
Ector County, Texas
Proposed vs Actual Wellpath - from KOP
Target Azimuth - 337 Degrees

6-20

6-20 was the next well. It was prepared (logged/conformance work / sectioning / cementing plug set) with the second rig by April 13. The lateral drilling rig moved onto 6-20 by April 17. The cement plug was dressed off from 4295' to 4535', the pilot/curve hole drilled to 4716 Millidarcy (MD) by April 22. The drilling of the straight lateral with the mud motor started on April 23.

The well was drilled to 4768' MD and surveyed. A loss of inclination and drift off to the northwest (NW) was found due to lack of directional control. The rotary steerable system's curve assembly was used to correct inclination angles and was drilled to 4814' MD. Azimuth, however, could not be corrected to direct well to the north (N) or northeast (NE). At this point the SCU team elected to try an alternative system for the next well and asked the contractor to continue drilling 6-23 until April 27.

The rotary steerable system's straight assembly was used to drill to 4830'MD, then switched back to mud motor and drilled to 5045' MD as of 6:00 a.m., April 27. The well was finally heated acid treated on coiled tubing on April 30 with the second workover rig.

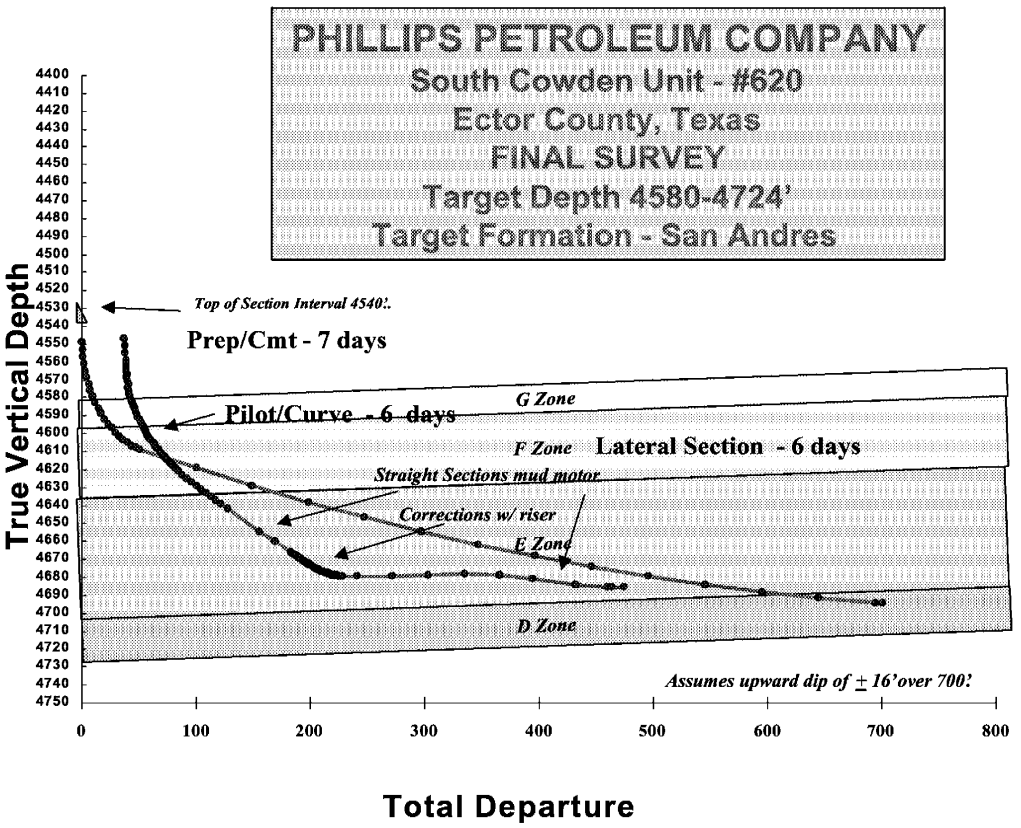
Well 6-20 well was disappointing because:

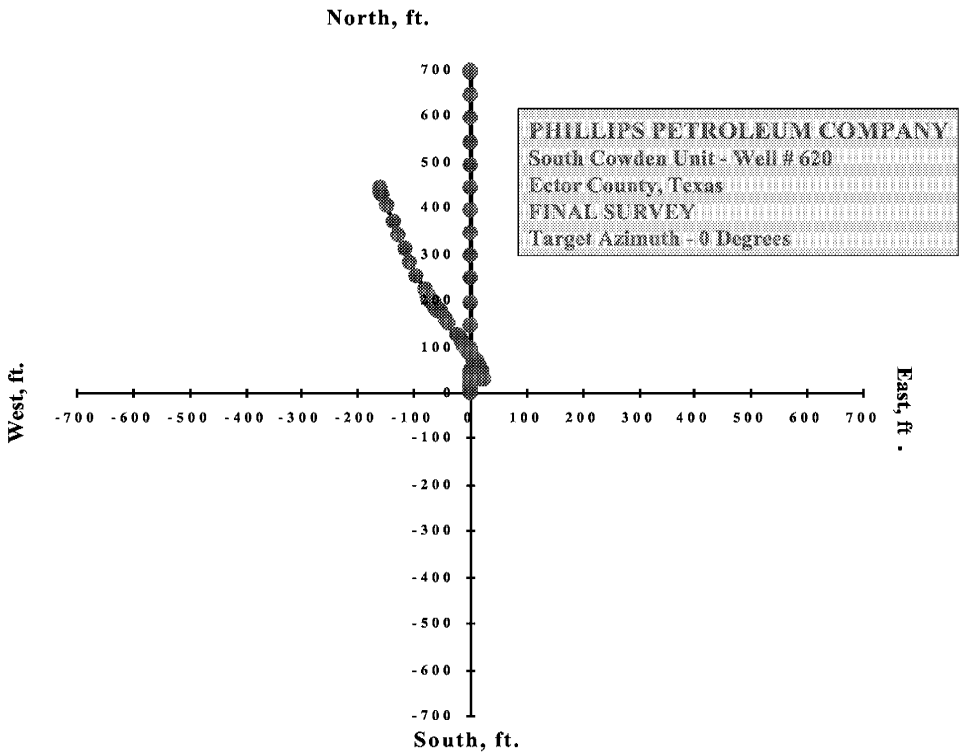
a) Departure was 480 feet at base of E zone, against a prognosed 630'in mid E zone.
b) Azimuth could not be corrected and well points to northwest, instead of north or northeast (as prognosed).
c) Slow penetration while drilling curved section was not improved.

The mud motor system, however, did appear to provide better penetration rates in the straight lateral section and did not require any fishing trips.

Integral for a successful Phase I redevelopment was demonstrating laterals could be drilled in a timely and cost effective manner. The success of South Cowden continuing as a CO_2 flood and continuing with Phase II redevelopment was a successful Phase I lateral drilling campaign. The results of the first three wells suggested Phase I had not accomplished this requirement, as reflected in the "scorecard" shown in the summary above.

The decision to use an alternate contractor for the final well was no reflection on the dedication and effort that the original company personnel had made. It was the fact that several approaches were attempted to give the rotary steerable system its best shot of success, but these had not been successful. This suggested an alternate drilling system was required.


PHILLIPS PETROLEUM COMPANY
South Cowden Unit - #620
Ector County, Texas
FINAL SURVEY
Target Depth 4580-4724'
Target Formation - San Andres
True Vertical Depth
Top of Section Interval 4540'.
Prep/Cmt - 7 days
Pilot/Curve - 6 days
G Zone
F Zone
Lateral Section - 6 days
Straight Sections mud motor
Corrections w/ riser
E Zone
D Zone
Assumes upward dip of ± 16'over 700'.
Total Departure



6-22

After reviewing several partner operated properties and discussions internally within the South Cowden team, Phillips elected to use a whipstock/mud motor system for the final well 6-22, developed by Scientific Drilling. The analogous work Scientific had performed throughout 1998 and 1999 suggested a 1500' well could be drilled at San Andres' depths in less than 10 days. This kind of performance was originally anticipated by the Torch system, but had proven too ineffective at the South Cowden lease.

The Scientific system is a four-stage process. Once the well is prepared a whipstock is installed, the casing is milled, and then the curved section drilled with a mud motor. Finally the lateral section is drilled with a mud motor. Surveying is performed using a MWD tool, typically taking 15 seconds to survey. Any corrections to direction are performed downhole.

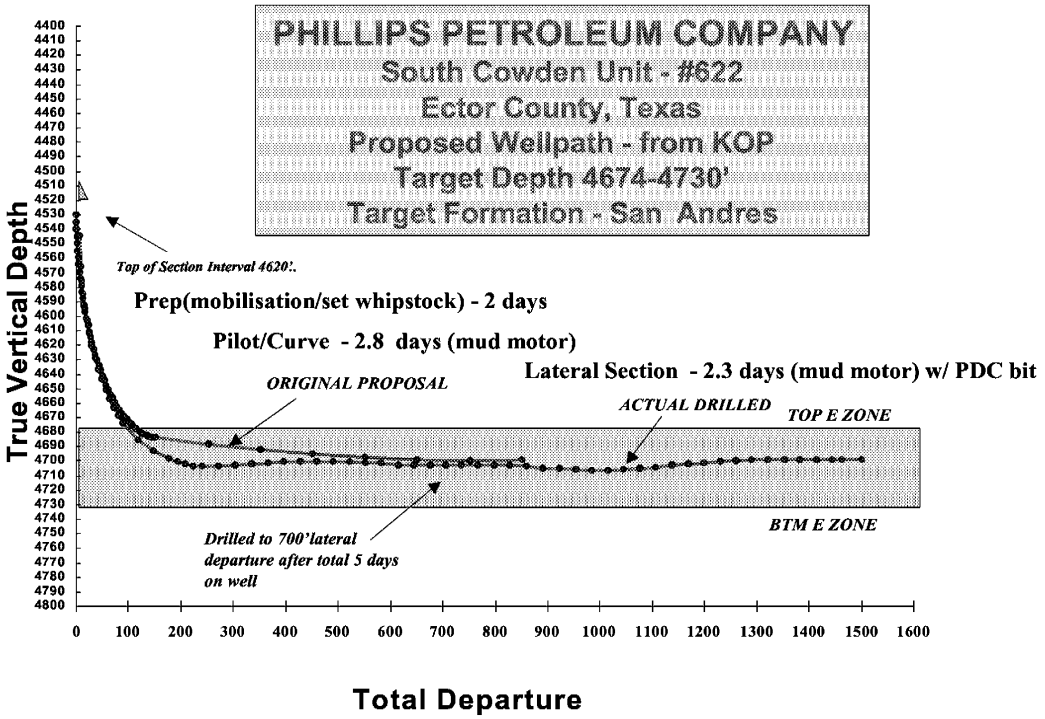
The obvious advantages of this system are that frequent surveying is possible and corrections to direction do not require the bottom hole assembly to be removed. The drawback with the system is the lost in hole charge incurred due to expensive tools downhole.

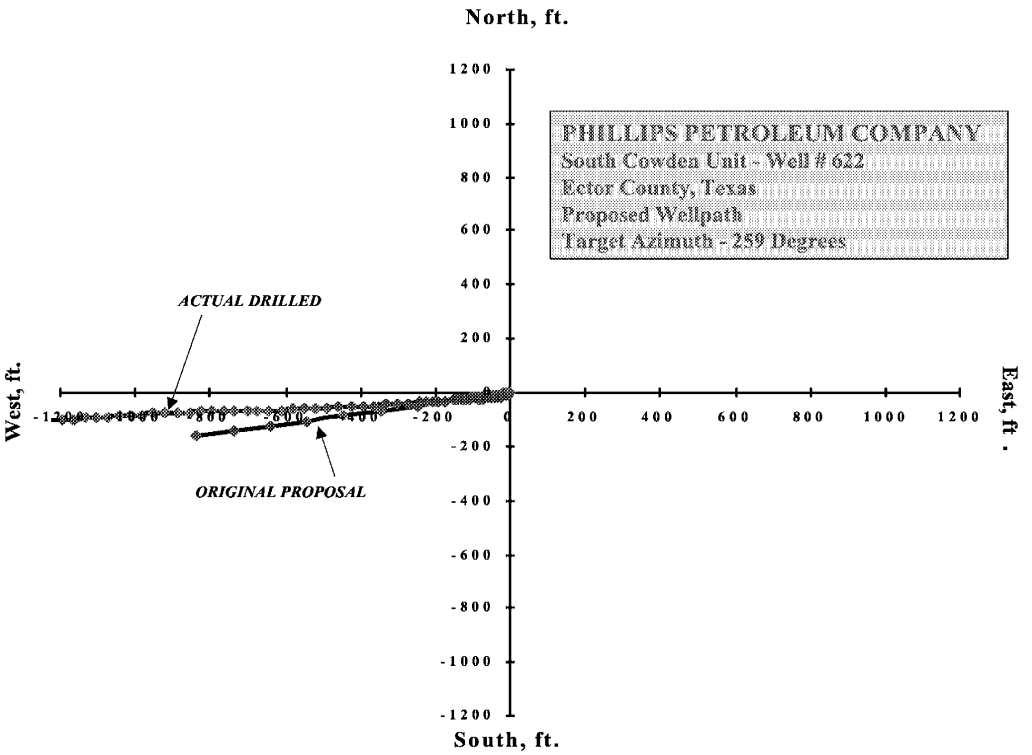
6-22 was the next well. It was prepared (log/conformance) with a second rig by May 7. The lateral rig moved onto 6-22 on May 9. Early on May 11 progress had been excellent. The well was drilling in the first stages of straight (horizontal) section of lateral. On the same day

by 4:30 p.m. 174' of straight section was drilled. By 7:00 a.m. the following morning 626' of straight section was drilled.

At this point, if drilling had been ceased and the well acidized/completed, total lateral cost would have been $135 thousand (k) to $140k. This included all logging, preparation, whipstock and lateral drilling. At this point we had accomplished a 700' lateral under 10 days for under $150k. We had therefore, demonstrated what was set out for Phase I and had found a technology suitable for Phase II development work.

Because of the excellent progress, drilling continued for an extra day to take the well departure to 1500'. The well reached total depth (TD) on the afternoon of May 13 and was then heat acid treated on May 15 using 15,000 gals acid compared to typically 7,500 gals for previous wells.





Compressor Upgrade

The compressor contractor designed a work program and started installation work in early March. Installation commenced on March 16 and was complete by March 27. The contractor also provided a safety review. The compressor was upgraded to re-cycle 4.5 MMSCF/D (Million Standard Cubic Feet Per Day) CO_2 instead of the previous 1.2 MMSCF/D.

Phase 1 Production Monitoring

Summary tables showing well tests for each lateral are at the end of this section.

7-13

The first well 7-13 was placed on production April 1, 2000. Prior to drilling the lateral withdrawal rates were 14 barrels of fluid per day (bf/d) and 4 barrels of oil per day (bo/d). The first 10 days of production averaged 217 bf/d (a 16-fold increase) and oil rates 104 bo/d (a 23-fold increase).

The dramatic increases were caused by drilling away from the poor quality rock at the original 7-13 location and into an area of known swept oil. The lateral was directed toward well 7-01, which had shown highest oil rates in the field over the last two years. Overall fluid rates have varied between 105 bf/d and 322 bf/d, and averaged 181 bf/d to October 2000; an average 13-fold increase in productivity.

6-23

The second well 6-23 was placed on production April 20, 2000. Prior to drilling the lateral withdrawal rates were 78 bf/d and 14 bo/d. The first 10 days of production averaged 346 bf/d (a 4-fold increase) and oil rates 5 bo/d (a decrease).

The increases were therefore, not as large as those observed in 7-13, probably due to drilling in similar quality rock and the lateral length being smaller. Overall fluid rates varied between 100 bf/d and 401 bf/d, and averaged 311 bf/d to October 2000; an average 4 -fold increase in productivity. Unusually, this well did not see the same level of water cut and gas-oil ratio observed prior to drilling the lateral, even though the well has the smallest departure at 300'. No large oil/CO_2 response has been observed in this well to date. Drilling into poor quality rock not swept by CO_2, moving North from 6C25H could cause this.

6-20

The third well 6-20 was placed on production April 29, 2000. Prior to drilling the lateral withdrawal rates were 56 bf/d and 45 bo/d. The first 10 days of production averaged 246 bf/d (a 4.5-fold increase) and oil rates 10 bo/d (a decrease).

The increases were, therefore, not as large as those observed in 7-13, probably due to drilling in similar quality rock and the lateral being smaller length. Overall fluid rates havevaried between 191 bf/d and 544 bf/d, and averaged 292 bf/d to October 2000; an average 5 -fold increase in productivity. A larger pump was installed in early June, which lowered the fluid level in the well and improved withdrawal rates. This well has steadily seen an increase in oil rates from 10 bo/d up to 90 bo/d. Water cuts have gradually reduced from 98% initially to 69%.

6-22

The fourth well, 6-22, was placed on production May 15, 2000. Prior to drilling, the lateral withdrawal rates were 56 bf/d and 4 bo/d (this was based on an offset well known to be producing just from the upper San Andres interval). The first 10 days of production averaged 481 bf/d (a 9-fold increase) and oil rates 5.2 bo/d (a slight increase).

After monitoring the initial production, monitoring fluid levels and knowing the well was drilled 1500' into the best rock in the field, it was felt the well was capable of producing at much higher rates. After installing a submersible pump, withdrawal rates increased dramatically to average 1485 bf/d (a 25-fold increase in productivity) and 40 bo/d. Rates have varied between 1050 bf/d and 1704 bf/d. Water cuts have been steady between 97 to 98%, with no oil/CO_2 response as yet.

Appendix J

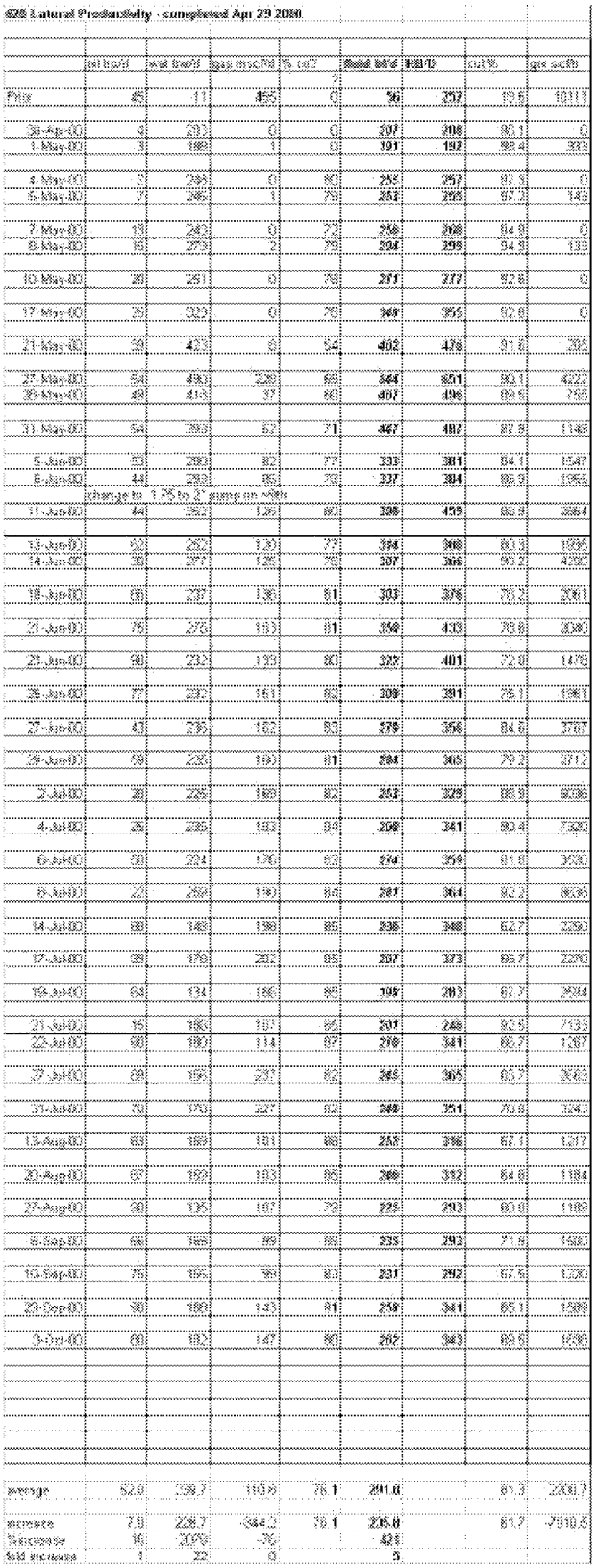
713 Lateral Productivity - completed Apr 1 2000

	oil bw/d	wtd bw/d	gas mscf/d	% cut	fluid bf/d	BD/D	cut%	gor scf/b
Prior	4.5	9	5	90	13.5	17	66.7	1111
2-Apr-00	118	108	232	79	226	352	47.8	1966
3-Apr-00	92	181	181	83	273	372	66.3	1967
4-Apr-00	80	98	163	61	178	266	55.1	2038
5-Apr-00	64	136	182	61	228	317	61.8	2167
6-Apr-00	112	107	156	74	219	313	48.9	1393
7-Apr-00	115	102	147	74	217	308	47.8	1278
8-Apr-00	122	91	129	74	213	299	42.7	1057
9-Apr-00	110	84	124	70	194	275	43.3	1127
11-Apr-00	109	67	119	78	176	254	38.1	1092
17-Apr-00	88	35	123	77	123	197	28.5	1398
20-Apr-00	63	42	130	74	105	171	40.0	1905
5-May-00	96	73	205	87	169	279	43.2	2146
11-May-00	67	78	189	79	145	240	53.8	2821
12-May-00	67	105	164	80	162	244	64.8	2877
24-May-00	64	127	194	85	191	287	66.5	3031
25-May-00	47	137	191	86	184	274	74.5	4064
29-May-00	28	178	201	88	206	295	86.4	7179
30-May-00	35	156	197	87	182	269	85.7	7577
31-May-00	32	132	199	44	154	227	78.2	4989
	having difficulty getting good test on well							
3-Jun-00	25	187	216	87	212	306	88.2	8640
	hook up back side to test sep directly on 8th June							
19-Jun-00	86.4	140.8	264	81	235.2	366	63.3	3056
	note above test only for 5 hrs, scaled up to 24 hrs							
26-Jun-00	52	113	327	87	165	311	69.6	6289
	back press reg valve installed on osg side							
28-Jun-00	26	158	344	88	184	330	85.9	13231
30-Jun-00	29	131	285	86	168	283	81.9	9828
1-Jul-00	30	102	149	86	148	211	72.9	3921
7-Jul-00	12	120	317	88	132	263	90.8	26417
10-Jul-00	13	309	1	84	322	326	96.0	77
15-Jul-00	120	25	307	84	146	303	17.8	2558
16-Jul-00	86	38	249	88	124	240	30.6	2895
19-Jul-00	111	64	223	84	175	296	36.6	2009
20-Jul-00	67	108	254	90	175	296	61.7	3791
22-Jul-00	113	206	55	77	319	373	64.6	487
25-Jul-00	128	27	362	77	155	336	17.4	2829
30-Jul-00	123	27	358	82	158	328	18.0	2911
4-Aug-00	82	57	349	84	139	302	41.0	4256
14-Aug-00	164	144	255	91	298	444	48.3	1662
18-Aug-00	79	79	136	89	158	234	50.0	1709
23-Aug-00	67	81	132	89	138	207	58.7	2316
26-Aug-00	69	59	133	86	128	201	46.1	1930
11-Sep-00	66	78	123	89	143	211	54.5	1893
28-Sep-00	61	79	143	88	138	202	60.8	2804
8-Oct-00	62	70	133	86	132	202	53.0	2097
average	75.2	105.7	197.4	81.2	180.9		56.7	3801.2
increase	70.7	96.7	192.4	-9.8	167.4		-10.8	2690.1
% increase	1571	1074	3847		1248			
fold increase	17	12	39		13			

623 Lateral Productivity - completed Apr 20 2000

	oil bbl/d	wat bbl/d	gas mscf/d	% cut	fluid bbl/d	RB/D	cut%	gor scf/b
Prior	14	64	186	0	78	857	82.1	13,286
21-Apr-00	3	362	0	0	365	366	99.2	0
22-Apr-00	3	354	0	0	356	357	99.3	0
23-Apr-00	6	347	0	0	353	355	98.3	0
24-Apr-00	12	341	0	0	353	356	96.6	0
25-Apr-00	6	351	0	0	357	358	98.3	0
26-Apr-00	4	332	0	0	336	337	99.8	0
27-Apr-00	5	342	0	0	347	348	98.6	0
28-Apr-00	4	332	0	0	336	337	98.8	0
29-Apr-00	4	311	0	0	315	316	98.7	0
14-May-00	3	305	0	0	308	308	99.0	0
15-May-00	4	305	0	0	307	308	98.7	0
27-May-00	6	217	0.1	70	222	223	97.7	20
28-May-00	4	272	0	0	276	277	98.6	0
2-Jun-00	4	289	0	0	293	294	98.6	0
4-Jun-00	4	288	0	0	292	293	98.6	0
6-Jun-00	4	277	0	0	281	282	98.6	0
25-Jun-00	7	302	0	90	309	311	97.7	0
28-Jun-00	8	314	0	0	323	326	97.2	0
29-Jun-00	9	314	0	76	323	326	97.2	0
30-Jun-00	9	302	0	76	311	314	97.1	0
3-Jul-00	10	303	0	0	313	316	96.8	0
5-Jul-00	10	259	0	0	269	272	96.3	0
10-Jul-00	13	309	1	84	322	328	96.0	77
13-Jul-00	16	312	1	84	320	333	95.1	63
17-Jul-00	18	307	1	84	325	338	94.5	56
18-Jul-00	16	278	1.2	86	289	294	94.5	75
21-Jul-00	18	303	2	81	321	327	94.4	111
22-Jul-00	19	314	2	81	333	338	94.3	105
23-Jul-00	19	314	2	81	333	338	94.3	105
26-Jul-00	16	277	2	84	293	298	94.5	135
29-Jul-00	17	315	2	83	332	338	94.9	118
3-Aug-00	19	275	2	85	294	308	93.5	135
7-Aug-00	23	292	2	87	315	322	92.7	69
20-Aug-00	27	286	13	85	313	327	91.4	630
25-Aug-00	24	303	26	91	327	345	92.7	1167
27-Aug-00	28	375	22	82	403	417	93.5	846
7-Sep-00	22	78	16	84	100	113	78.0	727
17-Sep-00	21	295	41	93	360	338	94.5	2000
9-Oct-00	21	234	42	86	255	278	91.8	2000
Average	11.8	293.2	4.7	44.8	311.0		96.9	286.6
Increase	-2.2	235.2	-181.3	44.8	233.0		13.6	-13085.1
Percentage	-15	367	-97		299			
fold increase	1	5	0		4			

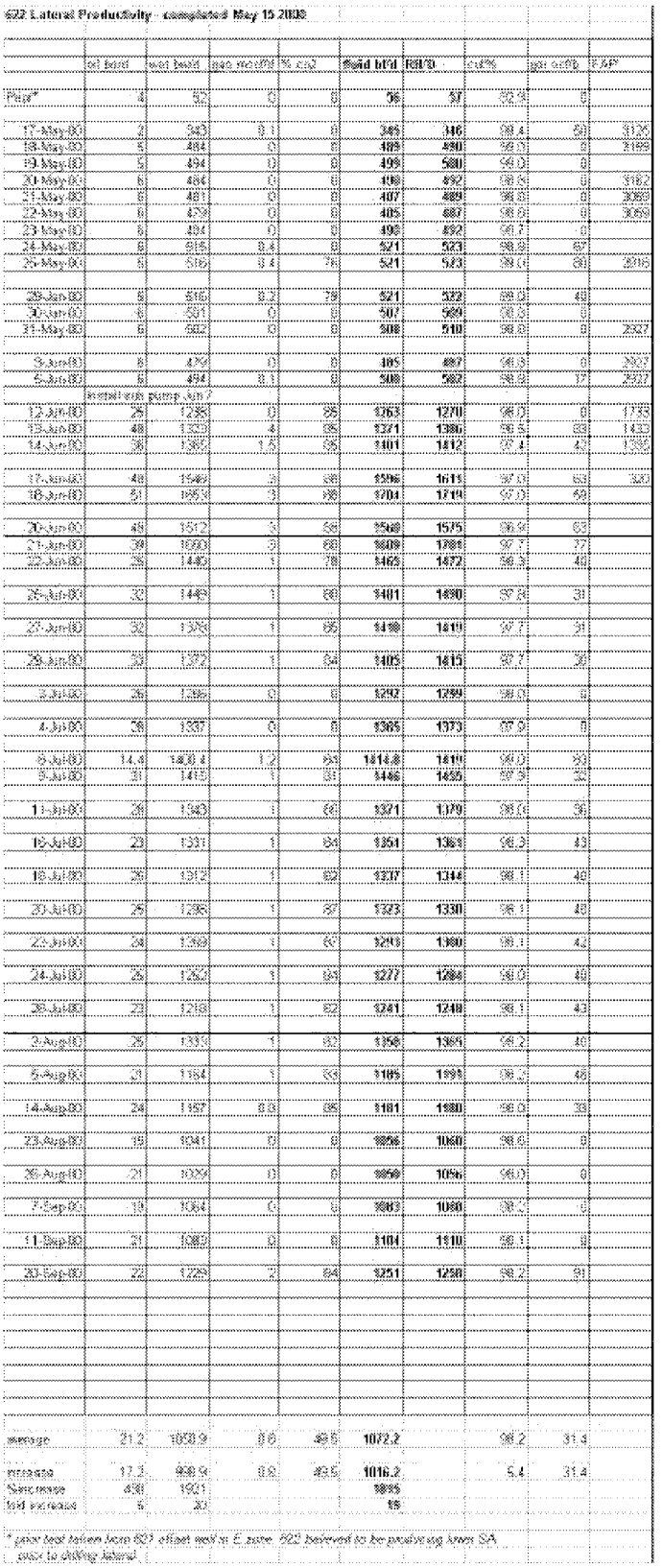
Appendix J



620 Lateral Productivity - completed Apr 29 2000

	oil bbl/d	wat bwl/d	gas mscf/d	% cd2	fluid bbl/d	RB/D	cut%	gor scf/b
				?				
Prior	45	11	455	0	56	257	19.6	10111
30-Apr-00	4	203	0	0	207	208	98.1	0
1-May-00	3	188	1	0	191	192	98.4	333
4-May-00	2	248	0	80	255	257	97.3	0
5-May-00	7	246	1	79	253	255	97.2	143
7-May-00	13	243	0	72	256	268	94.9	0
8-May-00	16	279	2	79	294	299	94.9	133
10-May-00	26	251	0	78	271	277	92.6	0
17-May-00	25	323	0	78	348	355	92.8	0
21-May-00	39	423	8	54	402	476	91.6	205
27-May-00	54	490	229	65	344	451	90.1	4222
28-May-00	49	418	37	66	407	496	89.5	755
31-May-00	54	393	52	71	447	487	87.9	1148
5-Jun-00	53	280	82	77	333	381	84.1	1547
6-Jun-00	44	293	85	79	337	384	86.9	1969
	change to 1.25 to 2" pump on ~9th							
11-Jun-00	44	262	126	80	306	459	88.9	2864
13-Jun-00	52	262	120	77	314	368	80.3	1995
14-Jun-00	38	277	125	78	307	366	90.2	4200
18-Jun-00	66	237	136	81	303	376	78.2	2061
21-Jun-00	75	275	163	81	350	433	78.8	3040
23-Jun-00	98	232	133	80	322	401	72.0	1478
26-Jun-00	77	232	161	82	309	391	76.1	1961
27-Jun-00	43	236	162	83	279	356	84.6	3767
29-Jun-00	59	235	160	81	294	365	79.2	2712
2-Jul-00	28	225	169	82	253	329	88.9	6036
4-Jul-00	25	235	183	84	260	341	90.4	7320
6-Jul-00	58	224	176	82	274	359	81.8	3530
8-Jul-00	22	259	190	84	281	364	92.2	8636
14-Jul-00	68	148	198	85	236	348	62.7	2290
17-Jul-00	69	178	202	85	207	373	66.7	2270
19-Jul-00	64	134	186	85	198	283	67.7	2594
21-Jul-00	15	188	187	85	207	248	92.5	7133
22-Jul-00	68	180	114	87	270	341	66.7	1267
27-Jul-00	69	156	237	82	245	305	63.7	3663
31-Jul-00	70	170	227	82	240	351	70.8	3243
13-Aug-00	63	169	181	88	252	316	67.1	1217
20-Aug-00	67	169	183	85	240	312	64.8	1184
27-Aug-00	90	135	187	79	225	293	60.0	1189
6-Sep-00	66	165	89	85	235	293	71.9	1500
10-Sep-00	75	156	99	83	231	292	67.5	1330
23-Sep-00	98	188	143	81	259	341	65.1	1589
3-Oct-00	88	182	147	86	262	343	69.5	1680
average	52.0	238.7	110.6	78.1	291.0		81.3	2200.7
increase	7.0	228.7	-344.3	78.1	235.0		81.7	-7910.5
%increase	16	2078	-76		421			
fold increase	1	22	0		5			

Appendix J



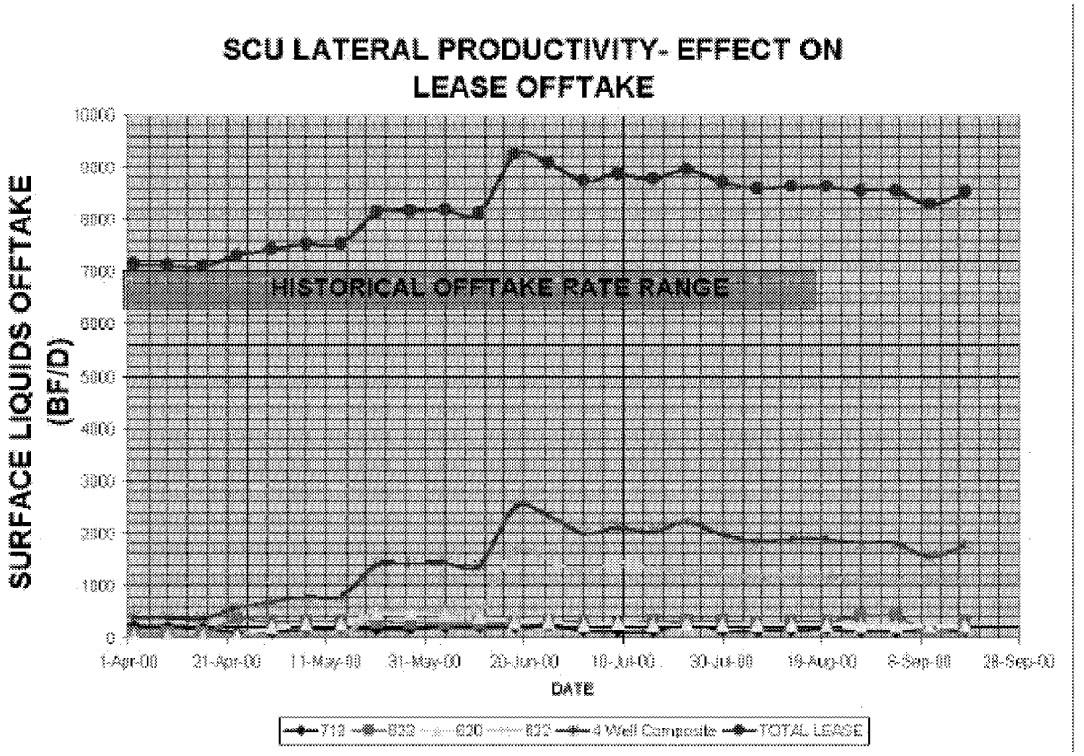
822 Lateral Productivity - completed May 15 2008

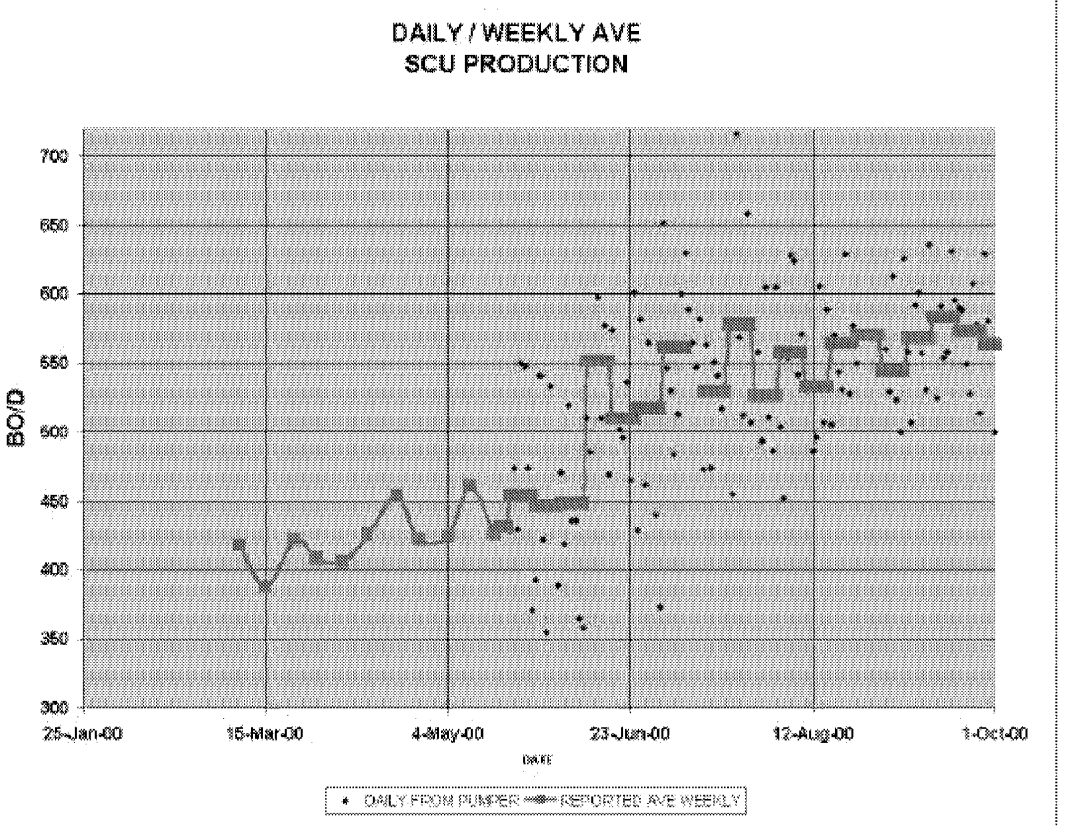
	oil bbl	wat bbl	gas mcf/d	% co2	fluid bbl/d	BBL/D	cut%	gas mcf/b	F-AP
Prod*	6	50	0	8	56	57	89.5	0	
17-May-08	2	343	0.1	0	345	346	99.4	29	3126
18-May-08	5	484	0	0	489	490	99.0	0	3189
19-May-08	5	494	0	0	499	500	99.0	0	
20-May-08	6	484	0	0	490	492	98.5	0	3182
21-May-08	6	481	0	0	487	489	98.5	0	3089
22-May-08	6	479	0	0	485	487	98.6	0	3069
23-May-08	6	484	0	0	490	492	98.7	0	
24-May-08	6	515	0.4	0	521	523	98.6	67	
25-May-08	6	516	0.4	78	521	523	98.6	68	3316
26-Jun-08	6	516	0.2	39	521	522	98.6	40	
30-Jun-08	6	501	0	0	507	509	98.6	0	
31-May-08	6	502	0	0	508	510	98.6	0	3227
3-Jun-08	6	479	0	0	485	487	98.6	0	3027
4-Jun-08	6	494	0.1	8	500	502	98.6	17	3017
	restart esp pump Jun 7								
12-Jun-08	25	1238	0	96	1263	1270	98.0	0	1735
13-Jun-08	48	1323	4	98	1371	1386	98.5	83	1433
14-Jun-08	36	1365	1.5	98	1401	1412	97.4	42	1394
17-Jun-08	48	1546	3	98	1596	1615	97.0	63	520
18-Jun-08	51	1653	3	98	1704	1719	97.0	59	
20-Jun-08	48	1512	3	98	1560	1575	96.9	63	
21-Jun-08	39	1690	3	98	1729	1788	97.7	77	
22-Jun-08	25	1440	1	78	1465	1472	96.3	40	
26-Jun-08	32	1449	1	96	1481	1490	97.8	31	
27-Jun-08	32	1378	1	96	1410	1419	97.7	31	
28-Jun-08	29	1382	1	94	1405	1415	97.7	36	
3-Jul-08	26	1266	0	0	1292	1299	98.0	0	
4-Jul-08	28	1337	0	0	1365	1373	97.9	0	
8-Jul-08	14.4	1800.4	1.2	93	1814.8	1819	98.0	83	
9-Jul-08	31	1415	1	91	1446	1455	97.9	32	
11-Jul-08	26	1343	1	66	1321	1379	98.0	34	
12-Jul-08	23	1331	1	84	1354	1361	98.3	43	
16-Jul-08	26	1312	1	82	1337	1344	98.1	40	
20-Jul-08	25	1295	1	97	1323	1330	98.1	40	
23-Jul-08	24	1369	1	80	1393	1400	98.1	42	
24-Jul-08	25	1252	1	84	1277	1284	98.0	40	
30-Jul-08	23	1218	1	82	1241	1248	98.1	43	
3-Aug-08	25	1333	1	83	1358	1364	98.2	40	
5-Aug-08	31	1154	1	93	1185	1191	98.2	46	
14-Aug-08	24	1157	0.8	88	1181	1188	98.0	38	
23-Aug-08	19	1041	0	0	1056	1060	98.6	0	
26-Aug-08	21	1034	0	0	1059	1064	98.0	0	
7-Sep-08	19	1064	0	0	1083	1088	98.2	0	
11-Sep-08	31	1080	0	0	1104	1110	98.1	0	
20-Sep-08	23	1228	0	84	1251	1258	98.2	91	
average	21.2	1050.9	0.6	49.5	1072.2		98.2	31.4	
increase	17.3	998.9	0.6	49.5	1016.2		5.4	31.4	
Sep increase	436	1921			1895				
bbl increase	5	30			15				

* prior test taken from 823 offset well in E zone. 822 believed to be producing from SA prior to drilling lateral.

Overall Lease Offtake

Since completion of Phase 1 lease offtake has improved from a historical range of 6500-7000 bf/d to 8000-9000 bf/d. This dramatic productivity improvement has helped reduce voidage balance, which will accelerate the reduction in overall reservoir pressure.





The effect on oil production from the lease was to increase productivity by 44% from a low of 400 bo/d at the start of Phase 1 operations to 575 bo/d at the end of the monitoring period.

2D18 Disposal Well/Water Injection Cut Back/CO_2 Injection Increase

Although not part of the original Phase 1 year 2000 redevelopment, it was decided to test the 2D18 disposal well. The well was drilled as a disposal well in the Canyon/Clearfork intervals. Regulatory approval was approved to inject up to 3000 pound per square inch (psi) surface injection pressure, but has never been used to date. This would require a large capital investment for a compressor to boost injection pressure.

A step rate test and injection log were planned to determine the wells' injectivity into the current Canyon and Clearfork barrels of water per day (bw/d) reservoir intervals. The well was tested in late April 2000. It was discovered that up to 7500 could be injected at the 3000 psi injection pressure.

Costs estimates were prepared for renting/purchasing a pump upgrade to inject at higher surface pressures. However, after starting up an unused 600 hp/1200 psig pump at the lease, rates of 2500 bw/d at 1000 psi were being injected in the well.

After reviewing historical water injection at the lease, the SCU team decided to cut back water injection in the south of the field. This would allow reservoir pressure around Tract 6 to lower and improve CO_2 movement down toward 6-22 well and allow greater volumes of CO_2 to be injected at 6C25H.

CO_2 injection re-commenced after the last lateral was drilled and downhole testing was complete. Injection was kept steady at 3 MMSCF/D in both 6C25H and 7C11H. After monitoring the 6C25H injection pressures and cutting back water injection in the southern part of the lease, injection rates were increased to 4 MMSCF/D by the end of June.

APPENDIX K

Redevelopment Phase 2 Preparation and Amendments

Summary

The basic lateral design was to kick off in the Grayburg interval, in a tight Anhydritic interval above the San Andres. Then drill the curve section to the top of the F zone. Small Grayburg sands are evident in some areas of the field between the kick off points and the top of the F zone. Therefore, after drilling to top F zone, Grayburg injectivity is tested (*see below). Then the straight section drilled to the final depth, normally in the mid D zone.

Cost estimates for Phase 2 activities were prepared under the assumption the near well areas, especially around leaseline injection wells, would have severe behind pipe and near well fracturing requiring conformance techniques to resolve. The contractors and techniques used for Phase 2 were essentially a continuation of the successful methodology involved with the drilling of the last well of Phase 1, which was a proven success.

Two wells, 7-15 and 6-29, were used as test wells to determine if the Stimtube/Heated acid technique could be expanded to additional South Cowden Unit (SCU) wells. The technique was being evaluated to boost upper San Andres productivity without causing behind pipe communication paths to lower San Andres zones.

Both 7-15 and 6-29 stimgun/heated acid treatments were performed but productivity testing revealed no real significant benefit of the technique. Although it appeared the technique did not induce communication paths to lower layers, the productivity of the wells had not changed or was reduced. Based on these results it was deemed necessary to start preliminary planning of additional producing laterals as an alternative technique for boosting upper layer productivity in the lease.

Horizontal well 7C11H required a conformance technique to prevent out of zone injection at the well's toe as part of Phase 2 activities. Halliburton developed a procedure involving the use of their proprietary "Diamond Seal" product, which would be injected at surface, en ter and seal the fracture system and then be washed out with coil tubing (CT).

Preliminary fine scale modeling suggested little need for re-entering old abandoned wells, and was therefore taken out of Phase 2 activities. Fine scale modeling results are discussed in the Appendices.

Phase 2 Preparation

Open Hole Logging

Open hole logging techniques were evaluated to find suitable technologies for open hole lateral section logging. The objective was to demonstrate, in one well, open hole logging could be implemented at South Cowden if required. The main obstacle for running logging tools is tight curvatures in the curve section of the laterals. As a consequence only short length, small ID tools will fit within these curvatures. Reeves Wireline was chosen to perform logging on one well, 2-27, as part of Phase 2 was identified for running their tool. It was later discovered, however, the tools require a compression sub to be installed above the tools,

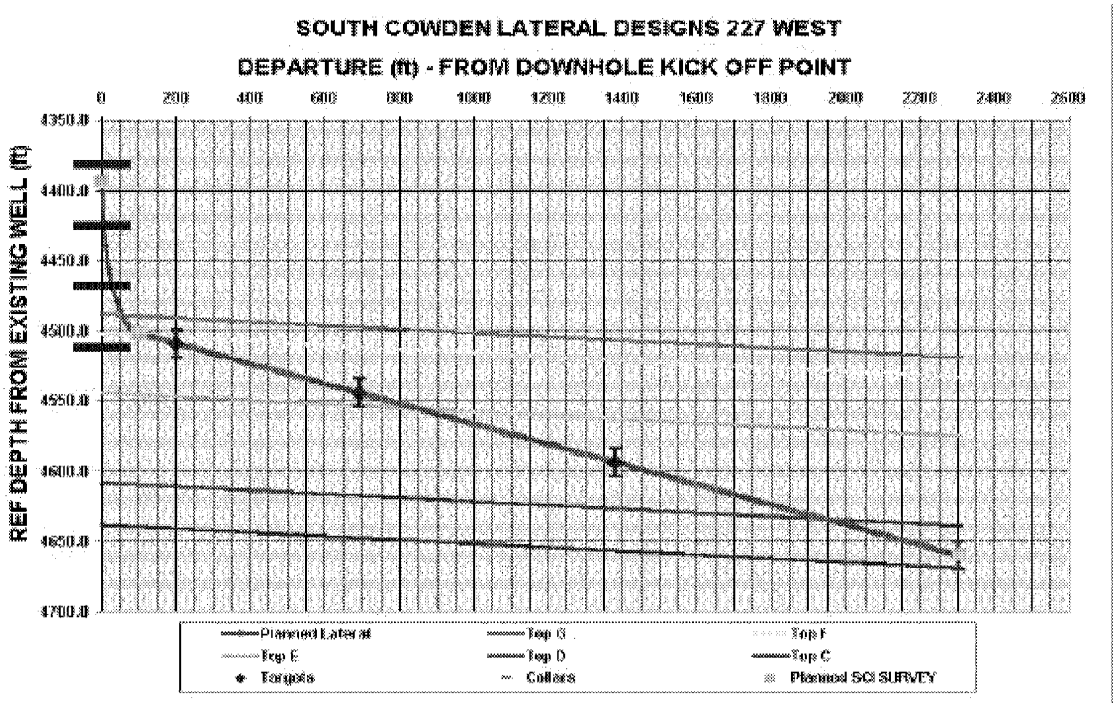
when the tools are run on coiled tubing. The smallest sub length available is too long to pass through.

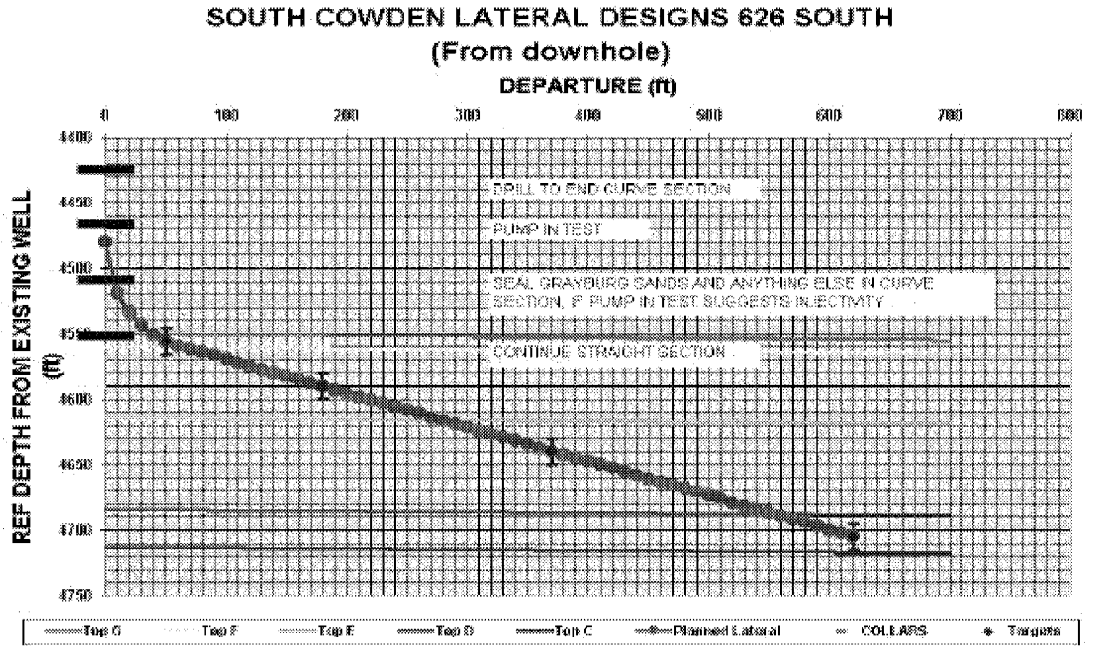
Lateral Planning

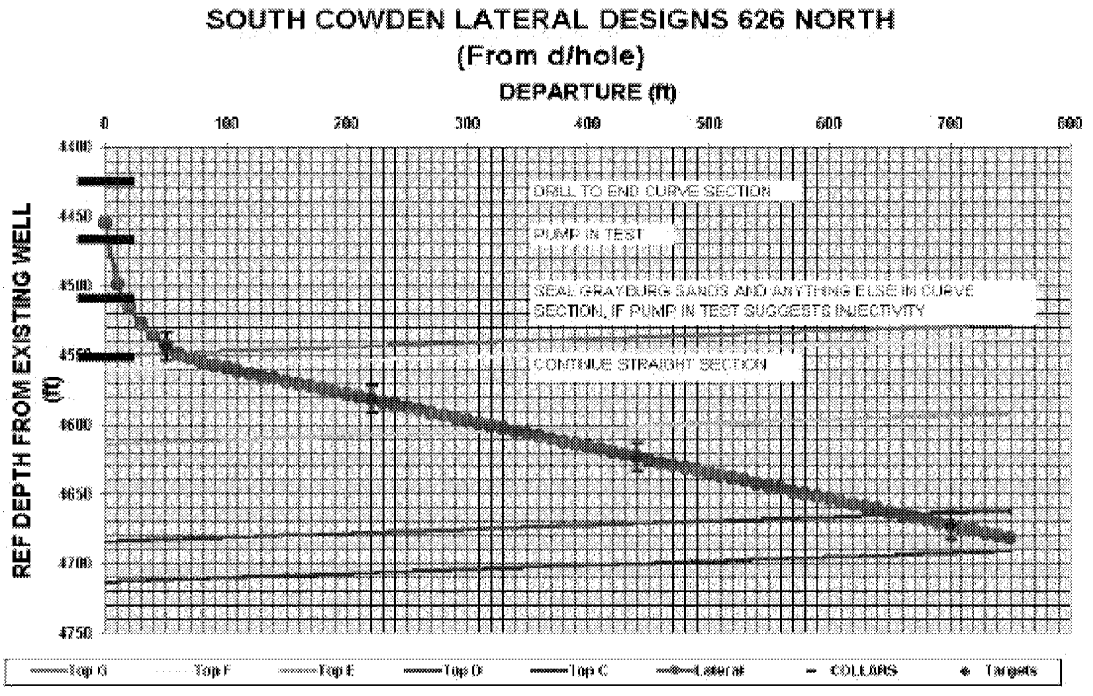
The SCU team met with lateral drilling contractor to discuss Phase 2 activities. Preliminary designs were made and refined for all lateral trajectories. The two major concerns were avoiding casing collars and ensuring the dog-leg-severity is kept within a reasonable limit.

The basic lateral design was to kick off in the Grayburg interval, in a tight Anhydritic interval above the San Andres. Then drill the curve section to the top of the F zone. Small Grayburg sands are evident in some areas of the field between the kick off points and the top of the F zone. Therefore, after drilling to top F zone, Grayburg injectivity is tested (*see below). Then the straight section drilled to the final depth, normally in the mid D zone. The figures below illustrate lateral designs for wells 2-27 (a single lateral) and 6-26 (a dual lateral).

As kick off points for laterals are in the Grayburg interval there maybe some slight injectivity in some of the thin, fairly low permeability Grayburg sands lying between the kick off point and top San Andres. Generally the sands are not expected to inject a great deal of CO_2 over time. If injectivity is noticed on the pressure test discussed above, then "Permseal", or an alternate, conformance methods would be squeezed into the sands to prevent long term CO_2 injection into these Grayburg sands. Permseal is a Halliburton propriety substance for sealing reservoir rock to reduce effective permeability to zero. This methodology was identified as a more cost effective approach when compared to full casing off of the curved section.




SOUTH COWDEN LATERAL DESIGNS 626 SOUTH
(From downhole)
DEPARTURE (ft)
0
100
200
300
400
500
600
700
800
4400
4450
4500
4550
4600
4650
4700
4750
REF DEPTH FROM EXISTING WELL (ft)
DRILL TO END CURVE SECTION
PUMP IN TEST
SEAL GRAYBURG SANDS AND ANYTHING ELSE IN CURVE SECTION, IF PUMP IN TEST SUGGESTS INJECTIVITY
CONTINUE STRAIGHT SECTION
Top G
Top F
Top E
Top D
Top C
Planned Lateral
COLLARS
Targets


SOUTH COWDEN LATERAL DESIGNS 626 NORTH
(From d/hole)
DEPARTURE (ft)
0
100
200
300
400
500
600
700
800
4400
4450
4500
4550
4600
4650
4700
4750
REF DEPTH FROM EXISTING WELL (ft)
DRILL TO END CURVE SECTION
PUMP IN TEST
SEAL GRAYBURG SANDS AND ANYTHING ELSE IN CURVE SECTION, IF PUMP IN TEST SUGGESTS INJECTIVITY
CONTINUE STRAIGHT SECTION
Top G
Top F
Top E
Top D
Top C
Lateral
COLLARS
Targets

Re-Entry Systems

A contractor was hired to evaluate re-entry systems for use in dual lateral wells. The objective was an in-expensive system that would allow re-entry of both laterals of a dual lateral well, without the need for well killing. Situations may arise in the future where wells may require coiled tubing cleanout or injection surveys in both laterals.

After review, the majority of systems available were fairly expensive for a small development such as SCU. Also, the likelihood of an expensive system having integrity over several years in hostile CO_2 environments was small. As a result no re-entry systems were included in the Phase 2 completions. The remaining option is to use a coiled tubing indexing tool to re-enter the top lateral, while leaving the whipstock in the lower lateral. The indexing tool allows orientation of bottom of the coiled tubing after applying certain pressures at surface.

Cost Estimates

Cost estimates for Phase 2 activities were prepared under the assumption the near well areas, especially around leaseline injection wells, would have severe behind pipe and near well fracturing requiring conformance techniques to resolve. The contractors and techniques used for Phase 2 were essentially a continuation of the successful methodology involved with the drilling of the last well of Phase 1, which was a proven success.

Permitting

Permitting for laterals were applied for with the Texas Railroad Commission (TRRC). As the leaseline wells' trajectories are straddling two separate leases, the TRRC needed clarification of the lateral design and re-assurances the wells on the leaseline would not be placed on production, as this would violate a commission rule. The leaseline laterals were permitted on a single lateral basis, with Northern laterals classed as Emmons wells and Southern as SCU wells.

Stimtube/Heated Acid Evaluation

As the Stimtube/heated acid treatment was an integral technique recommended for Phase 2, it was decided to evaluate the effectiveness of the technique prior to undertaking the multi-well campaign.

Stimtube/Heated Acid procedures were therefore prepared for wells SCU 7-15 and 6-29. Originally 7-10 and not 7-15 was chosen, but an injectivity survey performed on 7-10 suggested a large foamed cement squeeze was required to prevent behind pipe communication.

Wells 7-15 and 6-29 were picked as candidates. These wells have had poor offtake but have some of the best upper layer porosity (hence they should have good permeability/productivity). The Stimtube/heated acid treatment should therefore extend beyond any near well damage and stimulate into the upper layers and improve productivity.

Also, the two wells did not require too large a conformance treatment prior to the Stimtube work.

The two wells were essentially test wells to determine if the Stimtube/Heated acid technique could be expanded to additional SCU wells. The technique was being evaluated to boost upper San Andres productivity without causing behind pipe communication paths to lower San Andres zones.

Both 7-15 and 6-29 stimgun/heated acid treatments were performed at the end of September. Initial productivity testing revealed no real significant benefit of the technique. Although it appeared the technique did not induce communication paths to lower layers, the productivity of the wells had not changed or was reduced. Additional well tests were monitored and confirmed no long-term benefit of the technique.

Based on these results it was deemed necessary to start preliminary planning of additional producing laterals as an alternative technique for boosting upper layer productivity in the lease.

Injectivity Surveys

Prior to performing conformance techniques for existing vertical wells where laterals were planned, injectivity surveys were required to analyze behind pipe communication issues, and to improve the conformance design.

Initial attempts at performing the surveys were difficult due to high surface pressures and asphaltines preventing access to perforated intervals.

The best approach, for preventing high surface pressures (mainly caused by CO_2 in gaseous phase in the tubing), seemed to be to inject water for several days prior to running the survey. If, after being shut in for a day, CO_2 was still bled off at surface, water injection was continued until no CO_2 was bled off after 24 hours shut in.

Once a full column of water was established in the well, it was easier to perform injectivity testing as required by Halliburton to diagnose the severity of behind pipe issues. In some instances Halliburton representatives had enough well information and historical data without the need for an injection survey.

7C11H Conformance Technique

Horizontal well 7C11H required a conformance technique to prevent out of zone injection at the well's toe as part of Phase 2 activities. Halliburton developed a procedure involving the use of their proprietary "Diamond Seal" product, which would be inject ed at surface, enter and seal the fracture system and then be washed out with CT.

The Diamond Seal is designed to enter high conductivity fractures, and is physically unable to enter any formation rock. As a result, it can be easily pumped at surface until the fracture is

filled, any surplus Diamond Seal is washed out of the horizontal section, and if required Diamond Seal reapplied until the fracture is sealed.

Fine Scale Modeling

Core data from 8-19 was used to define a very fine scale model to determine the effects of vertical communication and out of zone injection.

It was concluded if upper layer CO_2 processing could be maintained, especially with offtake from production wells, then there was little incremental difference to CO_2 recovery.

Plugging and abandoning work for Phase2 was therefore removed. More detail of the fine scale modeling is discussed in the Appendices.