FINAL TECHNICAL PROGRESS REPORT

ADVANCED OIL RECOVERY TECHNOLOGIES FOR IMPROVED RECOVERY FROM SLOPE BASIN CLASTIC RESERVOIRS, NASH DRAW BRUSHY CANYON POOL, EDDY COUNTY, NM

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ABSTRACT

The Nash Draw Brushy Canyon Pool in Eddy County New Mexico was a cost-shared field demonstration project in the U.S. Department of Energy Class III Program. A major goal of the Class III Program was to stimulate the use of advanced technologies to increase ultimate recovery from slope-basin clastic reservoirs. Advanced characterization techniques were used at the Nash Draw Pool (NDP) project to develop reservoir management strategies for optimizing oil recovery from this Delaware reservoir. The objective of the project was to demonstrate that a development program, which was based on advanced reservoir management methods, could significantly improve oil recovery at the NDP. Initial goals were (1) to demonstrate that an advanced development drilling and pressure maintenance program can significantly improve oil recovery compared to existing technology applications and (2) to transfer these advanced methodologies to other oil and gas producers.

Analysis, interpretation, and integration of recently acquired geological, geophysical, and engineering data revealed that the initial reservoir characterization was too simplistic to capture the critical features of this complex formation. Contrary to the initial characterization, a new reservoir description evolved that provided sufficient detail regarding the complexity of the Brushy Canyon interval at Nash Draw. This new reservoir description was used as a risk reduction tool to identify “sweet spots” for a development drilling program as well as to evaluate pressure maintenance strategies.

The reservoir characterization, geological modeling, 3-D seismic interpretation, and simulation studies have provided a detailed model of the Brushy Canyon zones. This model was used to predict the success of different reservoir management scenarios and to aid in determining the most favorable combination of targeted drilling, pressure maintenance, well stimulation, and well spacing to improve recovery from this reservoir.

An Advanced Log Analysis technique developed from the NDP project has proven useful in defining additional productive zones and refining completion techniques. This program proved to be especially helpful in locating and evaluating potential recompletion intervals, which has resulted in low development costs with only small incremental increases in lifting costs. To develop additional reserves at lower costs, zones behind pipe in existing wells were evaluated using techniques developed for the Brushy Canyon interval. These techniques were used to complete uphole zones in thirteen of the NDP wells. A total of 14 recompletions were done: four during 1999, four during 2000, two during 2001, and four during 2002-2003. These workovers added reserves of 332,304 barrels of oil (BO) and 640,363 MCFG (thousand cubic feet of gas) at an overall weighted average development cost of \$1.87 per BOE (barrel of oil equivalent).

A pressure maintenance pilot project in a developed area of the field was not conducted because the pilot area was pressure depleted, and the reservoir in that area was found to be compartmentalized and discontinuous. Economic analyses and simulation studies indicated that immiscible injection of lean hydrocarbon gas for pressure maintenance was not warranted at the NDP and would need to be considered for implementation in similar fields very soon after production has started. Simulation studies suggested that the injection of miscible carbon dioxide (CO_2) could recover significant quantities of oil at the NDP, but a source of low-cost CO_2 was not available in the area.

Results from the project indicated that further development will be under playa lakes and potash areas that were beyond the regions covered by well control and are not accessible with vertical wells. These areas, covered by 3-D seismic surveys that were obtained as part of the project, were accessed with combinations of deviated/horizontal wells.

Three directional/horizontal wells have been drilled and completed to develop reserves under surface-restricted areas and potash mines. The third well has not been on production long enough for an accurate assessment but initial results from it are encouraging. Cumulative production from the first two wells through August 31, 2005 was 235,039 BO, 816,592 MCFG and 310,333 barrels of water (BW). Total estimated reserves from all three of the horizontal wells are 878,135 BO and 3.87 BCFG. The ratio of net revenue to cost for the first two wells is approximately 2.9 to 1 for an oil price of $30 per barrel that existed when the wells were drilled.

Based on recent pricing trends, a detailed reserve study for the project was performed that assumed an oil price of $40 per barrel and a gas price of $7 per MCFG. These results show that this project has acceptable economics and similar projects can be economically developed as long as oil and gas prices remain over $30 per BOE. The nine wells that were part of the DOE Class III project have produced 526,947 BO and 3.04 BCFG. Ultimate recovery from the nine project wells is projected to be 1.3 million barrels of oil and 6.73 BCF natural gas. Using a 6 to 1 ratio gas to oil, this equates to 2.35 million BOE. The before tax return on investment for the project is slightly in excess of three to one, and taxes and royalties from the project will generate almost three times the DOE contribution to the project.

EXECUTIVE SUMMARY

Background

The Nash Draw Brushy Canyon Pool (NDP) in southeast New Mexico was one of the nine projects selected in 1995 by the U.S. Department of Energy (DOE) for participation in the Class III Reservoir Field Demonstration Program. The goals of the DOE cost-shared Class Program were to: (1) extend economic production, (2) increase ultimate recovery, and (3) broaden information exchange and technology application. Reservoirs in the Class III Program were focused on slope-basin and deep-basin clastic depositional types.

Production at the NDP is from the Brushy Canyon formation, a low-permeability turbidite reservoir in the Delaware Mountain Group of Permian, Guadalupian age. A major challenge in this marginal-quality reservoir was to distinguish oil-productive pay intervals from water-saturated non-pay intervals. Because initial reservoir pressure was only slightly above bubble-point pressure, rapid oil decline rates and high gas/oil ratios were typically observed in the first year of primary production. Limited surface access, caused by the proximity of underground potash mining and surface playa lakes, prohibited development with conventional drilling.

The first phase of the project was a "Science Phase" in which detailed reservoir characterization and project data, including the acquisition of 3-D seismic data, were analyzed to provide the basis for delineating appropriate reservoir management strategies. During Phase I, the feasibility of a pilot project was to be determined and the results of the pilot would be extrapolated to a full field implementation, if technically and economically feasible. Phase II of the project was the "Implementation Phase" in which results of the pilot testing would be considered for expansion to the remainder of the field. Details and results of the NDP project are documented in annual reports[1-10] and a final Phase I report[11] submitted to DOE and in several technical papers[12-24] that resulted from the project.

Overview of Budget Period 1 (Science Phase)

As part of the DOE project, six vertical data wells (#12, 23, 24, 25, 29, and 38) were drilled (**Fig. 1**) to evaluate the seismic survey, characterize the reservoir, and provide insights into production characteristics. The geological modeling, seismic interpretation, reservoir characterization, and simulation studies obtained in Phase I provided a sound technical basis for the field development program undertaken in Phase II of the project.

Geological Analysis

The faults and depositional character of the deeper structures (Morrow and Bone Spring) provided the depositional surface for the shallower sequences and created the bench-step surface being used to describe the Brushy Canyon reservoir.[1-4] The Brushy Canyon reservoir at the NDP was found to be much more complex than initially indicated by conventional geological analysis. Although the original evaluation was that both the "K" and "L" sandstones were the major oil producing intervals, the results of this study show the primary oil productive zone at the NDP is the "L" sandstone While the original concept pictured the NDP as a collection of thin channel sands continuously distributed between wells, the results from Phase I show the subzones within the sandstones are lenticular and are not always continuous from well to well which can affect flow paths between wells. The interpretations of the advanced reservoir analysis show the oil accumulation in Brushy Canyon interval exists areally as pods or fairways and vertically as stacked micro-reservoirs. Examination of the core under ultraviolet light revealed the discontinuous character of the hydrocarbon distribution mixed with water zones throughout the pay interval. This correlates with the erratic vertical distribution of oil and water saturations calculated from log analysis.

Advanced Log Analysis

To evaluate the highly laminated micro-reservoirs that make up the pay zones in the Brushy Canyon interval, a log evaluation technique[1,11-14] was developed to identify pay that is laminated with wet zones. Using transmissibility values to calculate production from the various zones for vertical wells in the NDP, results showed that while the bulk of the oil production at the NDP comes from the "L" sandstone, much of the water is produced from the "K" and "K-2" sandstone, if the latter zone is present. By properly identifying productive pay intervals, oil recovery from the Brushy Canyon reservoir at the NDP was calculated to be 16.6%, rather than the 10% as initially estimated. This methodology for identifying net pay in complex reservoirs can be applied in other highly laminated sandstone formations.

Geophysical Results

Vertical seismic profiles and a 3-D seismic survey were acquired to assist in interwell correlations and facies prediction.[1] By conducting pre-survey VSP wave testing and by careful processing of 3-D seismic data, the thin-bed turbidite reservoirs at the NDP could be imaged, and the individual Brushy Canyon sandstones could be resolved.[2] The interpreted seismic data indicated that the NDP may be highly compartmentalized, and that some of the compartments, for some sand sequences in the "L" zone, may be much smaller than 300 acres.[11] Results of seismic data[1-3,16,17] and other interpretations were used for targeted drilling in high-grade areas of the NDP.

Geostatistics and Seismic Attribute Analysis

The potential value of geostatistical techniques for estimating interwell reservoir properties, with infill drilling as a possible goal, was investigated. However, NDP wells primarily cover the center part of the initial seismic survey, so new techniques[18-24] were developed to extrapolate reservoir properties beyond the area directly constrained by wells. A new technique[18-22] utilized a non-linear multivariable regression (Neural Networks) with seismic attributes as inputs and porosity, water saturation, and net pay as outputs. A Fuzzy Ranking System was used to help decide which seismic attributes were most useful for evaluating reservoir properties. The regression equations allowed the prediction of the three reservoir properties in areas without direct well control, and the resulting computed maps, such as hydrocarbon pore volume, were generated fieldwide. Results suggest that predictions of interwell and fieldwide reservoir properties are possible.

Reservoir Modeling and Simulation

After a fieldwide geological model of the NDP was completed, a detailed simulation model of a proposed pilot area was developed for the most productive "L" sand.[1,2] Reservoir simulation studies were performed to evaluate various injection methods, including waterflooding, lean gas, and carbon dioxide, for the pilot area.[2,3] Immiscible gas injection for pressure maintenance in the proposed pilot area at the NDP was ruled out because of low reservoir pressure and compartmentalization of productive intervals. The low permeabilities and relative permeability effects may preclude waterflooding at the NDP. Miscible carbon dioxide (CO_2) flooding may be a viable method at the NDP, and areas of the field already under production could be candidates for miscible CO_2 injection, but a low-cost source of the gas was not available in the vicinity of the NDP. Injection of immiscible hydrocarbon gas for pressure maintenance may be viable in undeveloped regions if those areas are not pressure depleted or compartmentalized and if injection is initiated early. The results of the reservoir studies prompted the decision to shift consideration of a pressure maintenance pilot project into Phase II, when new areas of the NDP were drilled.

Overview of Budget Period 2 (Implementation Phase)

The original Statement of Work included a pressure maintenance pilot project in a developed area of the field. The proposed pressure maintenance injection was not conducted because the pilot area was pressure depleted, and the seismic results suggested the pilot area was compartmentalized. The major emphasis in Phase II was to use the advanced characterization results to design extended-reach/horizontal wells to tap into predicted "sweet spots" that are inaccessible with conventional vertical wells.

The activities during Budget Period #2 included the continued analysis of data, the acquisition of interests belonging to non-consenting partners, acquisition of additional 3-D seismic, completion of additional zones in exiting producing wells, and the design, drilling, and completion of deviated/horizontal wells to access oil reserves beneath potash mines and playa lakes.

Gas Processing & Injection

The economics of processing gas at the NDP to recover liquids and reinject lean gas for pressure maintenance were evaluated.[8] Based on this analysis, the best economic course was to continue to sell the gas outright. The additional capital cost required to install processing and injection facilities was not justified given the estimated future profit. However, if a processing and reinjection system had been installed near the beginning of the NDP project some 10 years ago, the increased oil and gas production volumes would have made better economic sense. When the analysis was done, the NDP had produced in excess of 1.25 million BO and 7.2 billion cubic feet of gas (BCFG). These volumes, together with increased oil recoveries from pressure maintenance, may have allowed a more rapid return and ultimately a higher multiple on the gas processing and injection facilities.

Well Workovers

To develop additional reserves from existing vertical wells at low costs, the Advanced Log Analysis techniques developed Phase I were used to evaluate zones behind pipe in uphole zones of the Brushy Canyon interval. From 1999 to 2003, fourteen recompletions were done in thirteen NDP wells which resulted in the development of economical reserves during a period of relatively low crude oil prices. These workovers at the NDP provided additional reserves of 332,304 BO and 640,363 MCFG at a weighted average development cost of $1.87 per barrel of oil equivalent.

Directional/Horizontal Wells

In Phase II of the project, Strata Production Company demonstrated that it is possible to drill deviated/horizontal wells to develop reserves in areas not accessible by vertical drilling (**Fig. 2**). Strata drilled NDP Well #36, the first directional/horizontal well in the NDP, in 2001[6,7] at a cost of $3,143,441. A second directional/horizontal well, NDP Well #33, was drilled and completed in 2002[8,9] at a cost of $2,502,942. A third directional/horizontal well, NDP #34, was drilled and completed in 2005 at a cost of $2,985,518. Cumulative production from NDP Well #36 through August 31, 2005 was 142,111 BO, 515,776 MCFG and 100,929 BW. Production has stabilized at about 61 BOPD, 360 MCFG and 120 barrels of water per day (BWPD), and the GOR has stabilized at 6 MCFG/BO. Cumulative production from NDP Well #33 through August 31, 2005 was 92,928 BO, 300,816 MCFG and 209,404 BW. Total estimated reserves are 380,355 BO and 2,255,814 MCFG for Well #36, 209,988 BO and 628,585 MCFG for Well #33, and 287,792 BO and 985,402 MCFG for Well #34. The ratio of net revenue to cost is approximately 3.5 to 1 for Well #36 and 2.3 to 1 for Well #33 at an oil price of $30 per barrel that existed when the wells were drilled. A detailed economic analysis is reported later that reflects more recent pricing.

Characterization & Simulation

A reservoir simulation[7] was performed to estimate the drainage area of NDP Well #36. The simulator was populated with structure, permeability, and porosity derived from actual well data where available and with a simple nearest neighbor geostatistical calculation for interwell data. A plot of actual production versus simulator production indicated the reservoir area attributable to NDP Well #36 is approximately 130 acres.[7] The reservoir simulation model has proved to provide a good match to actual oil production. The actual produced gas volume appears higher than predicted and, after comparing the field volumes to the actual sales volumes, the test volumes reported from the field volumes are 20 to 30% too high. Sales volumes plus fuel gas used in production facilities were much closer to the predicted gas volumes.

Additional 3-D Seismic Tests and New Drilling Targets

The 3-D seismic survey for the north end of the NDP incorporated receivers located on the shore and into selected areas of the playa lakes to record data from beneath mined areas. In the fourth quarter of 2002, a total of 24.6 km^2 (9.5 square miles) was shot, with 4371 receivers and 1191 source points.[8] We believe that this is the first 3-D seismic survey designed to model the Delaware formation where surface and subsurface constraints, including voids created by underground potash mining, has been attempted. The lower Delaware sands were successfully imaged, and the new survey has refined the original interpretation of the NDP reservoir. Analysis of the 3-D seismic data identified a target in the NE/4 of Section 12 for the next deviated/horizontal well. Drilling of the NDP Well #34 began in March 2005 from the NDP Well #19 location. Well #34 was completed and put on production in June 2005, and after 30 days production stabilized at 90 BOPD, 250 MCFG and 180 BWPD from the toe interval.

Production and Reserves

The production database for the NDP was updated through August 31, 2005. These data were added to the history of each well to update the decline curves and to project ultimate recoveries as well as to assess the effects of interference and production strategies. The nine wells that are part of the DOE Class III project (NDP Wells #12, 23, 24, 25, 29, 33, 34, 36, and 38) have produced 526,947 BO, 3.04 BCFG, and 2,132,427 BW as of September 1, 2005. Total reserves added as a result of the DOE project include more than 1.3 million barrels of oil and more than 6.7 BCFG (see **Table 1**). Total taxes and royalties to the federal and state governments will be almost three times the DOE contribution to the project.

Technology Transfer Activities

Technology transfer of the data and results from the NDP project have been a major component of the project. In addition to the reports and technical papers mentioned previously, Strata has participated in several workshops: a Characterization Workshop at Roswell, NM in August 1996, a Fracture Stimulation Workshop at Hobbs, NM in September 1996, a Logging Workshop at Midland, TX in September 1997, a Reservoir Characterization Workshop at Hobbs, NM in September 1997, a Core Workshop at Midland, TX in February 1998, and a Horizontal Drilling Workshop at Midland, TX in May 2005. Details of the latter workshop are available from the Southwest Region of the Petroleum Technology Transfer Council (PTTC).[25] All of the technology transfer activities to date in Phase I and Phase II of the project are listed in the major section in Technology Transfer. Strata Production Co. has also developed a webpage[26] that summarizes results from the project.

INTRODUCTION

The Nash Draw Brushy Canyon Pool, operated by Strata Production Company (Strata), is located in Sections 12, 13, and 14 T23S-R29E, and Section 18 T23S-R30E, in Eddy County, New Mexico, about 28.2 km (17.5 miles) southeast of Carlsbad. Production at the Nash Draw Pool (NDP) is from the basal Brushy Canyon zones of the Delaware Mountain Group of Permian, Guadalupian age. The NDP was one of the nine cost-shared field demonstration projects in the U.S. Department of Energy Class III Program. A major goal of the Class III Program was to stimulate the use of advanced technologies to increase ultimate recovery from slope-basin clastic reservoirs.

Production Constraints at the Nash Draw Project

The Brushy Canyon formation at the NDP is a low-permeability turbidite reservoir of marginal quality. The basic problem at the Nash Draw Pool (NDP) was the low oil recovery that is typically observed in similar Delaware reservoirs. A challenge in developing the reservoir is to distinguish oil-productive pay intervals from water-saturated, non-pay intervals. Additionally, because initial reservoir pressure was only slightly above bubble-point pressure, rapid oil decline rates and high gas/oil ratios are typically observed in the first year of primary production. Further, limited surface access, caused by underground potash mining and surface playa lakes in the area (see **Fig. 1**), prohibits development with conventional drilling in some parts of the reservoir. By comparing a control area using standard infill drilling techniques to a similar area developed using advanced reservoir characterization methods, the goal of the project was to demonstrate that a development program based on advanced methodology can significantly improve oil recovery.

The Nash Draw Technical Team

The NDP project involved the demonstration of a virtual company concept involving a small independent oil producer and geographically dispersed experts.[15] Typical of small independent producers, Strata Production Co. lacked the in-house expertise to address all of the needs of the Class III project, and, therefore assembled a diverse team of experts to analyze and implement the Nash Draw project. As lead organization for the Class III project, Strata was responsible for project management and day-to-day operations from its location in Roswell, NM. Territorial Resources, Inc. and Scott Exploration in Roswell, NM provided geological expertise. Dr. Bob A. Hardage of the Texas Bureau of Economic Geology (BEG) in Austin, TX provided seismic and geophysical expertise. The Petroleum Recovery Research Center (PRRC), located in Socorro, NM, provided reservoir characterization, technical support, and reporting functions. Pecos Petroleum Engineering, Inc. (PPE), also of Roswell, provided reservoir, production, and drilling engineering services. Dave Martin and Associates, Inc., with virtual employees in Los Alamos and Albuquerque, NM, and in Houston, TX, provided reservoir modeling and simulation services. The latter two organizations had a lead role in technology transfer activities.

Initial Data Collected

Initial data collected for the project included log analyses, sidewall and whole core tests, relative permeability data, PVT data, capillary pressure data, vertical seismic profiles, and a 3-D seismic survey.

Well Data

In the early stage of the project, data from the NDP was compared to log and core data from nearby Delaware fields, and producing characteristics and recovery efficiencies were compared to analog Brushy Canyon reservoirs. Log and core data from wells in the E. Loving Delaware Pool, Texaco wells southeast of the NDP, and from Maralo wells offsetting the NDP were obtained and analyzed. Structure maps and cumulative oil, gas, and water production for the E. Loving Pool, and logs and available core data from all three fields were analyzed and compared to data from the NDP.

Sixteen wells in the E. Loving Pool in Section 14, T23S-R28E were selected as an analogy to the NDP. These wells represent varying structural positions and corresponding production characteristics. Logs were obtained from each well, structure maps were constructed, and available core data were obtained for the wells in the study area. Structure and isopach maps were developed in the analog area using the same criteria that were used in the NDP area.

The data acquisition portion of the project at the NDP included compiling new and existing reservoir and engineering data. As part of the DOE project, six new wells were drilled for data acquisition, and the NDP then consisted of 17 vertical producing wells and one salt water disposal well (see **Fig. 1)**. Multiple sidewall cores were obtained for analysis from each new well, and 61.9 m (203 ft) of full core was cut from Well No. 23 for laboratory analysis. The whole core obtained from Well No. 23 was cut from the "J" zone through the "L" zone. Basic core data including porosity, permeability, oil and water saturations, grain density, show description, and lithology descriptions, were measured for each foot of core**.** Special core analysis included wettability, capillary pressure, relative permeability, thin sections, X-ray diffraction, and Scanning Electron Microscope (SEM) studies. Detailed petrographic and x-ray diffraction analyses were performed on thin-section samples from Wells #15 and #23. Conventional suites of logs (neutron porosity, formation density, gamma ray, caliper, dual lateral log, micro resistivity log) were obtained in all of the wells, and a magnetic resonance tool was run in Well No. 23 for comparison to the core analysis.

A data file was prepared for each well that included digitized log files, perforations, cement programs, tracer logs, completion information, and frac treatments. These data were used to allocate production, estimate drainage areas, determine productivity, estimate saturations for each interval, and prepare data files for reservoir simulation.

Petrophysical data were used to develop a methodology for accurately predicting oil productive zones. The whole core data were used to calibrate the digitized logs and determine productive and water zones in each interval. The application of porosity/permeability transforms and relative permeability data to each zone yielded flow capacity data for each interval. By applying the core-calibrated log analysis to the entire basal Delaware section, oil-productive zones could be identified, reserves could be estimated, production rates could be predicted, and water-productive zones could be avoided.

Production, transmissibility, and capillary pressure data were combined with geological interpretations to develop reservoir maps. A detailed correlation of the basal Brushy Canyon sandstones was performed in order to better understand the lateral and vertical distribution of the reservoirs. Detailed correlations also provided a more accurate geological model for use in the reservoir simulation forecasts. Wireline log and core data were compiled for each of the wells within and directly adjacent to the NDP for the purposes of constructing the maps for the initial structural and stratigraphic model.

Seismic Tests

Vertical seismic profiles and a 3-D seismic survey were acquired to assist in interwell correlations and facies prediction. The advanced characterization effort of the NDP team integrated the geological, geophysical, petrophysical, geostatistical, production, and reservoir engineering data. The stratigraphic framework was quantified in petrophysical terms using innovative rock-fabric/petrophysical relationships calibrated to wireline logs.

A vertical seismic wavetest and two vertical seismic profiles (VSPs) were recorded in Well No. 25, and a 3-D seismic survey was acquired to aid the characterization of the NDP reservoir. The VSP data, including a zero-offset and a far-offset image, were obtained to assess seismic noise caused by nearby subsurface mining and normal oilfield activities including truck traffic, gas compressors and pumping units as well as to determine the optimum vibroseis parameters for the 3-D survey. As a result of the VSP work, the 3-D seismic grid at the NDP was redesigned to produce acquisition bins measuring 16.8 m by 33.5 m (55 ft by 110 ft). During data processing, a trace interpolation was done in the source direction to create interpretation bins measuring 16.8 m by 16.8 m (55 ft by 55 ft). For the 3-D survey at the NDP, a total of 917 source points were recorded to create a 3-D coverage across an area of 20.4 km^2 (7.9 sq. mi.).

Stratigraphic Framework/Geological Model

Structure and isopach maps based on successive interpretations of the main NDP geo-body were imported into Landmark's Stratigraphic Geocellular Model (SGM®) to create a stratigraphic framework model. These interpretations were based on well data from wells within and directly adjacent to the NDP. After a preliminary 3-D stratigraphic model was developed, all surface intersections in the multi-layered model were eliminated by fine-tuning the relationships between the different structural surfaces using isopach maps. These surface intersections occurred due to the sparse well control in some areas and relatively thin sand sub-units within the pool itself. The final model was constructed from the bottom up using the Bone Spring surface as the basal surface.

Production, petrophysically-derived storage and transmissibility distributions at the wells, special core analysis data, and geological interpretations were combined to arrive at a reservoir description that honored all of the available data. It was necessary to perform a detailed correlation of the sands in the basal Brushy Canyon sequence in order to better understand the lateral and vertical distribution of the reservoirs. Detailed correlations also facilitated a more accurate geological model for use in the reservoir simulation phase of the study. The data were compiled into a spreadsheet for ease of use between all members of the project team.

The full geological model of the NDP was based on inverse distance-weighted interpolation of the relevant reservoir attributes between wells. Special attention was given to the area around the proposed pilot injection project. A twenty layer model of the "L" sand, which was responsible for about 95% of the oil production in the pilot area, was developed to account for the highly lenticular distribution of reservoir oil.

Geostatistical techniques coupled with 3-D seismic attributes were used to extrapolate petrophysical properties into the interwell area. Successively refined geological reservoir models were developed by the interdisciplinary team. Reservoir characterization and simulation studies were used to predict the distribution of remaining oil saturation, to assess the feasibility of a pressure maintenance pilot injection test, and to optimize development drilling programs.

Activities of the Virtual Team

Advanced technologies were used to provide communication and coordination between the team members located in five different geographic areas. The Nash Draw virtual team[15] used the Internet and high-capacity data transfer to exchange data, results, graphics, interpretations, and conclusions between each group. Petrophysical and production databases were shared electronically with all of the project team members. Geological interpretations in the form of digitized two-dimensional structures and isopach maps generated by the geology team were exported as annotated contour files to the reservoir characterization team. The reservoir characterization team constructed three geological models based on the successively refined interpretations from the geology team and the petrophysical databases developed by the engineering team. In turn, the reservoir characterization team created a hypertext report with graphics extracted from the geological models which could be examined by means of a Web browser by each of the technical team members. This rapid access to work in progress was nearly as effective in integrating the reservoir characterization activities as co-location of the project team. The concept also allowed a small producer the ability to access technical expertise on an as needed and affordable basis.

RESULTS AND DISCUSSION

Production at the NDP is from the Brushy Canyon sandstone formation at a depth of about 1829-2134 m (6600-7000 ft). Reservoir and fluid data are listed in **Table 2**.[1,12,1,3] The relatively low porosity and permeability of the reservoir coupled with an initial reservoir pressure only slightly above bubble point pressure contribute to the low oil recovery factor. A major challenge in this marginal-quality reservoir was to distinguish oil-productive pay intervals from water-saturated non-pay intervals.

Geological Analysis

The sandstone units of the basal Brushy Canyon sequence of the Delaware Mountain Group in this study represent the initial phase of detrital basin fill in the Delaware Basin during Guadalupian time. The Delaware sands are deep-water marine turbidite deposits. Depositional models[27,28] suggest that the sands were eolian-derived and were transported across an exposed carbonate platform to the basin margin. Interpretations of the associated transport mechanisms[29,30] suggest that the clastic materials were deposited episodically, and were transported into the basin through shelf by-pass systems along an emergent shelf-edge margin.

The structural trend at the NDP is North-South to Northeast-Southwest, and there were at least three depositional events. The sandstone reservoirs of the Brushy Canyon sequence lie above the Bone Spring Formation (**Fig. 3**). The top of the Bone Spring is marked by a regionally persistent limestone varying from 15.2 to 30.5 m (50 to 100 ft) in thickness. This surface provides an excellent regional mapping horizon. Regional dip is to the east-southeast at about 100 ft per mile in the area of the NDP. The structural dip resulted from an overprint of post-depositional tilting, and this overprint is reflected in the reservoir rocks of the Delaware formation and impacts the trapping mechanism in the sands.

The Brushy Canyon reservoir consists of thin stacked sandstones; vertical permeability is extremely low, and horizontal permeability is poor to fair. Locally, the three sands of interest at the NDP are referred to as the “K”, “K-2”, and “L” sands (**Fig. 3**). These sands can be easily correlated from well to well over many square miles. Each of the sands is a composite of a series of stacked micro-reservoirs (**Fig. 3**) that vary from 0.3 to 1.8 m (1 to 6 ft) in thickness. Lateral extent of reservoir quality facies at the NDP may only be a quarter of a mile (0.4 km) or less in some areas.[1] Analysis of whole core and drilled sidewall core data[1] have shown that individual micro-reservoirs may be oil bearing, water bearing or transitional in nature. In addition, the sands have been found to have little or no vertical permeability from one micro-reservoir to the next. The "K" and "L" sandstones, the main producing intervals of the Brushy Canyon formation, have multiple lobes, and both sandstones can be divided into four sub-units.

Mineralogy of the “K” and “L” sandstones are similar[1]. Both zones contain some clays, including illite and chlorite. Compared to the "L" sandstone, the “K” sandstone has up to 2% more chlorite that occludes permeabilities and may have influenced the higher initial water saturations.

Petrographic and scanning electron microscope (SEM) studies[1] showed that the sands have a very complex composition and pore structure. Even the best of these sands would be considered "dirty" reservoirs. In general they can be described as subarkose, calcitic, very slightly dolomitic, slightly clayey, silty, and poorly sorted. Grains are subangular to subrounded, there is evidence of framework grain dissolution, and some secondary porosity occurs by grain dissolution. Clay that is present coats some of the grains and fills some of the pores. Productive reservoirs have porosity values ranging from 11 to 18 percent and permeability values ranging from 0.5 to 4 millidarcies (md).

Generally, the rock is fine-grained to very fine-grained, massive to very-thinly laminated. There is some evidence of turbulence as exhibited by sets of low-to-medium angle cross-bedding within some of the sand units. Evidence of bioturbation occurs in some of the shaley and silty zones. Carbonate clastic debris is also present in some intervals within the core. Examination of the core under ultraviolet light shows the discontinuous character of the hydrocarbon distribution throughout the pay interval. This correlates with the erratic vertical distribution of oil and water saturations calculated from the log analysis.

Initial Development Plan

Initially, it was believed that the NDP was composed of thinly bedded channel sandstones more or less continuously distributed between wells. The initial geological interpretation suggested that the Brushy Canyon sandstones in the NDP appeared to be blanket type sands. However, data and analyses obtained in this project suggest the sandstones at the NDP are laterally discontinuous and complex in nature.

The overall compositional character and discontinuity of the sands in these reservoirs has made log analysis, well completions, and predictability (i.e. where do we drill next) difficult for many years. These laminated sands with fine-grain to very-fine grain size and clay content typically yield "wet" saturation calculations, even in productive sands. Bound water in the clay coated sand grains is immobile. Clays and migrating fines have always required that special consideration be given to drilling and completion fluids. Operators are always looking for the "water free" Delaware sand completion. Given the nature of the sands in the NDP, water-free completions are not possible.

The initial development of the NDP was based on subsurface mapping of key horizons that had mudlog shows in various sands. A typical approach to developing Delaware sand prospects in southeast New Mexico has commonly involved searching the files for mudlogs and core data. This led to either drilling new wells offsetting those with shows or re-entering existing boreholes. In the case of the NDP, both methods were employed in the initial phase of development. The first well, the NDP Well #9, was drilled and completed in June, 1992. Subsequent drilling led to mixed results. While no dry holes were drilled, some wells performed better than others. Prediction of better quality reservoir facies remained a big challenge early on in the project. Early subsurface mapping showed the NDP as having more of a blanket sand morphology. With continued drilling the interpretation evolved into a more complex reservoir, having two primary sand depocenters trending in a north-south to northeast-southwest direction. Even with more data incorporated, the prediction of high quality reservoir sands was difficult.

Part of the development program in the NDP called for a pressure maintenance program for enhancing recoveries from these reservoirs. The area chosen included NDP Wells #1, #5, #6, #9, and #14. These wells were chosen because of their close proximity to one another. They are arranged in a 5-spot pattern, and pressure buildup tests indicated that they were in communication.

Early Project Results

By the end of 1995, 15 wells had been drilled at the NDP, and results were still mixed. The first 13 wells were drilled using conventional geological interpretations, and estimates indicated that ultimate recoveries per well will range from 40,000 BO to 150,000 BO and the average recovery per well would be 90,000 BO. Well quality could not be accurately predicted using subsurface geology and conventional data interpretation.

A third geological picture evolved in which there were possibly three depocenters. This interpretation could also be substantiated using bottomhole pressure data and isopach mapping of capillary pressure data. Using this new, more detailed interpretation, NDP Well #25 was drilled in early 1996 at a location that was thought to be in the middle of a prolific sand depocenter. Log and core data showed that the primary reservoir, the ”L” Sand, had just 1.2 m (4 ft) of net pay. Subsurface maps had predicted in excess of 9 m (30 ft) of net pay in this zone. Thus, the reservoir characterization activities focused on providing a better understanding of the NDP sandstone formations.

Methodology for Identifying Net Pay Zones

Because of the inherent difficulty in assessing pay zones in the Brushy Canyon formation, a new methodology was developed to identify productive oil intervals.

Comparison of NDP Data to Nearby Delaware Fields

Core data from all three nearby Delaware fields, the E. Loving Pool, the Texaco, and the Maralo fields offsetting the NDP, correlated very well in the "L" zone, but there was less agreement in the data from the "K" and "K-2" zones (see **Fig. 4**). Rock characteristics in the E. Loving analog area were similar enough to those in the NDP to allow accurate comparisons of the production data and characteristics of the two areas.

Log and Core Analyses

A major problem in evaluating potentially productive zones in Delaware sands is that wireline logs do not provide a definitive answer regarding what zones are productive and, most important, the amount of reserves recoverable from a particular well. This is primarily due to the highly laminated nature of the Delaware oil zones that are mixed with water zones. The resolution of the wireline logs is not good enough to arrive at accurate measurements for zones less than one foot in thickness. To compensate for the lack of wireline log data, full cores and sidewall cores were used to confirm the presence of productive zones by measuring fluid permeabilities and residual oil saturations. A core-calibrated log analysis procedure was developed to give accurate data with a minimum number of sidewall cores. This is a PC-based computer analysis system that is easily adapted to most sandstone reservoirs.

Core Calibrated Log Analysis

Wireline log and core data for all wells within and adjacent to the NDP were compiled. These included data from offset wells and wells in the E. Loving Field analog area. The basic log suite used in this analysis was a gamma ray, compensated neutron, formation density, dual laterolog and microlaterolog across the “K”, “K-2”, and “L” sands. Sampling log data at one-half foot intervals proved adequate for calculations in these Delaware zones.

Sidewall core data from each well were compiled, and porosity/permeability (□/k) relationships were determined. These relationships were compared to the whole core data and found to be in good agreement. Porosity/permeability relationships were determined by performing a regression analysis to determine the best straight-line fit of the data (see **Fig. 5**). Core data from the offset and analog wells were calibrated to characterize the uniformity of the zones over the area. The porosity and permeability relationships for each of the basal Brushy Canyon sands in the study area were found to be very uniform from well to well.[2,3]

Porosity/permeability relationships were developed from the sidewall cores and full core analysis. The flow unit variables “a” and “b” were determined for each of three sand types identified in the basal Brushy Canyon interval:

$$k = 10^{a\phi - b} \qquad (1)$$

Values for the flow unit variables are given in **Table 3**. The core data were analyzed to develop a transform to correct the compensated neutron and formation density log cross-plot porosity to yield a corrected porosity based on the whole core porosity. The relationship between cross-plot log porosity (logs run on a limestone matrix with a grain density of 2.71 gm/cc) and sandstone core porosity was determined to be:

$$\phi_{CORR} = (\phi_{x\text{-}plot} \times 0.786723) + 3.201193 \qquad (2)$$

By plotting core porosity versus cross-plot porosity, a quality check determined if the logs and core data were in agreement as well as determined missed core points. A correction factor can be applied to the log data to calibrate the logs to the core data.

Following the sidewall core methodology used to identify pay zones, a method was devised which identified pay zones using the core-calibrated log analysis. This analysis requires the following steps:

1. Obtain an accurate history of the resistivity of the mud filtrate (R_{mf}) while drilling the potentially productive zones. Obtain accurate R_{mf} values for the mud used while logging. Correct the R_{mf} values to bottomhole temperature using Arp's Equation:
   $$R_{mfcorr} = R_{mf@75^{o}F} \text{ x } (75^{o}+7)/(T_{amb}+7+((\text{depth}/100 \text{ ft}) \text{ x } g_T)) \qquad (3)$$

2. Correct porosity values using the cross-plot vs. core porosity transform in Equation 2. (Apply correction factor if needed.)

3. Calculate a residual oil saturation (S_{or}) using the R_{mfcorr} and ϕ_{corr} values in the equation $S_{or} = 1\text{-}S_{xo}$ (4)

   where

   $$S_{xo}= ((F_r \text{ x } R_{mfcorr})/R_{xoMSFL})^{0.5} \quad (5)$$

   and

   $$F_r=0.81/\phi^2 \quad \text{(Simplified Humble Formula)} \quad (6)$$

4. Calculate a S_{or} value for each interval in the digitized logs, and sort out the intervals with S_{or} values greater than the residual oil values in the cores. A residual oil cutoff of 20% was used in the NDP analysis. Since intervals with low or no residual oil saturation have a low probability of being oil productive and intervals with high residual oil saturations have a high probability of being oil productive, this was the first sorting step in the process of determining productive zones. These intervals are potentially productive zones and can be processed with other criteria to arrive at an accurate determination of the productive zones.

5. Because of the thin-bed nature of the Delaware formation, a deep resistivity log is influenced by the zones on either side of a productive zone; this averaging of approximately 0.9 m (3 ft) of zone and invasion leads to low Rt measurements. Low Rt values yield high S_w calculations and pessimistic interpretations of potential productive zones. To compensate for the averaging of thinly bedded reservoirs by the deep resistivity tool, an adjustment factor was used to multiply the observed Rt value by this correction factor to obtain a corrected Rt value (Rt_{corr}). This correction factor can be obtained by calibrating to a known productive zone where S_w is known, and it can be used to calibrate the calculations by finding the correction factor that yields S_w calculations which match actual production and test data. The most often used correction factor at the NDP was 1.1, and when that correction is multiplied by the Rt value, this gave a value of Rt that was 10% higher than measured. By applying a S_w cutoff of less than 60% to the prospective intervals, only intervals that had favorable relative permeability values were included in the sample of potentially productive zones.

6. The next sorting criteria is the gamma ray (GR) value from the logging suite. By eliminating intervals with GR values greater than 70 API units, shales and shaley sands are eliminated from consideration as productive zones. Shaley sands have low permeabilities and are seldom productive.

7. The relative permeability data and the permeability/porosity relationships indicate that porosity values less than 11% yield permeabilities below the level that are productive at the NDP. Therefore, only zones with a corrected porosity of 11% or greater were included in the final set of intervals that were projected to be productive.

8. Using S_w, ϕ_{CORR}, and other reservoir parameters, an original-oil-in-place (OOIP) value can be calculated for each interval on the digitized log. The OOIP value cutoff at the

NDP was a value greater than 0.039 m^3/m^3 (300 bbl/ac-ft).

An example of the final output of the core-calibrated log analysis is shown in **Table 4**. The data in **Table 4** were used to calibrate the logs and determine pay distribution in each zone.

Identification of Net Pay

By performing a detailed core-calibrated log analysis of S_{or}, S_w, and porosity, an analysis was applied to the digitized logs to determine the productive and the water zones in each interval. Each well was calibrated to match production, net pay, and transmissibility. By calculating a kh/μ value for each interval, production rates and cumulative production were allocated to each interval. The transmissibility for each layer was used as input into reservoir simulation model along with saturation data to determine the producing characteristics of each layer. The application of porosity/permeability transforms and relative permeability data to each zone yielded flow capacity data for each interval (see **Fig. 6**). These data show that the bulk of the oil production at the NDP comes from the "L" sandstone, but much of the water is produced from the "K" and "K-2" sandstone, if the latter zone is present. By properly identifying productive pay intervals, oil recovery from the Brushy Canyon reservoir at the NDP was calculated to be 16.6%, rather than the initial estimate of 10%.[2]

By applying the core-calibrated log analysis to the entire Delaware section, oil productive zones can be identified. This procedure provides a method of predicting future production rates from log analyses as well as a rationale for avoiding water productive zones. As a result, reserves can be better estimated. This procedure has proven to be an accurate predictive tool for new wells at the NDP and other Delaware reservoirs in the region.

Geophysical Program

Considerable geophysical activity occurred in year one of the project to aid the characterization of the NDP reservoir system. The critical component of the geophysical database necessary for the reservoir characterization effort was a high-quality 3-D seismic survey over the NDP.

Vertical Seismic Profiles

There were multiple reasons for shooting the 3-D seismic survey at the NDP. One reason was to develop a more refined geological model that gave better resolution of the structural aspects of the trap. A second reason was to try to determine whether or not the reservoirs in the basal Brushy Canyon sequence could be imaged using thin-bed seismic techniques. To properly prepare and plan for this 3-D seismic effort, a vertical seismic wavetest was first done in the centrally located NDP Well # 25 to characterize the seismic noise induced by surrounding subsurface mining and routine oilfield activity and to define the optimum vibroseis parameters that should be used to generate 3-D seismic wavefields. Concurrent with this wavetest, vertical seismic profile (VSP) data were also recorded in NDP Well # 25 to establish a precise depth-to-time conversion function for interpreting the 3-D seismic data and to produce a first-look seismic image of the targeted thin-bed "K" and "L" turbidite reservoirs. These VSP data were instrumental in setting the size of the stacking bins used in the subsequent 3-D seismic program.

VSP calibration data acquired in NDP Well # 25 established: (1) the top of the Bone Spring was a robust reflection peak, (2) the “L” sequence was associated with the first reflection trough immediately above the Bone Spring, and (3) the “K” sequence began just above the first reflection peak above the Bone Spring (**Fig. 7**). The reflection character of both the “K” and “L” events changed significantly north of the well which implied variation in the reservoir system and was a direct indication of stratigraphic changes or facies changes, or both.

3-D Seismic Survey

Using the information provided by the vertical wavetest and vertical seismic profile, a 3-D seismic survey was designed and implemented. The recorded data were quite high quality due to the extensive pre-survey testing and planning, and the rigorous processing sequence that was applied to the 3-D field records. A total of 917 source points were recorded to create a 3-D coverage across an area of 20.4 km^2 (7.9 square miles).

Fig. 8 shows the source-receiver line geometry used for the 3-D survey. Results from the 3-D seismic data were used to generate amplitude maps (**Figs. 9 and 10**) that show high amplitude areas and the producing trends. Well productivity appeared to directly correlate with the amplitude of the dominant “K” reflection peak and “L” reflection trough. Details of the acquisition and interpretation of the seismic results are presented elsewhere[1,16,17]

The amplitudes of the reflection peak and trough associated with the “K” and “L” sands varied significantly over the NDP, and the most facies-sensitive attribute was reflection amplitude. A map of maximum negative reflection amplitudes for the “L” sand across the 3-D seismic image space is displayed as **Fig. 10**. The strong visual correlation between the areal distribution of the high-amplitude “L” reflections and the positions of the better producing wells (NDP Wells #19, #11, and #15) documents an important principle that should be considered when siting future NDP well locations: as the amplitude of the “L” reflection trough increases, the productive potential of the L sequence increases. The amplitude of the “K” reflection peak looks much like this “L” reflection trough map, with higher reflection amplitudes again occurring at the better producing locations.[1]

The visual correlation between well performance and the “L” reflection amplitude exhibited in **Fig. 11** can be expressed in a quantitative way and can be used in reservoir simulators to calculate critical fluid-flow parameters from the 3-D seismic amplitude volume. In particular, statistically significant linear relationships were established between reflection amplitudes of the “L” sequence and three critical “L” reservoir properties: net pay, porosity-feet, and transmissivity to oil and water.

Crossplots of the relationships among these parameter pairs provided equations[2] to describe the distribution of the respective reservoir-data populations. This suite of equations represents numerical relationships that can be used to convert the “L” reservoir reflection trough amplitudes in the NDP 3-D data volume into estimates of the “L” reservoir net pay, porosity-feet, and fluid transmissivity in areally continuous cells measuring 16.8 m x 16.8 m (55 ft x 55 ft), which is the smallest spatial sampling provided by the 3-D seismic volume.

After acquisition of the 3-D seismic data, two wells were drilled: NDP Well #29 located in the NW/SE of Section 13 and NDP Well #38 located in the SW/SW of Section 13. To evaluate these wells in relationship to the other wells in the pool, transmissivity of the "L" zone was compared. The average transmissivity value of the "L" zone is 12.5 md-ft/cp, and the values for NDP Wells #29 and #38 are 18.97 md-ft/cp and 7.43 md-ft/cp, respectively. While NDP Well #29 had transmissivity values 50% higher than the average well, the cumulative production will be reduced due to partial depletion of the reservoir pressure. NDP Well #38 had a net sand section equivalent to other wells, but the porosity and permeability values were lower than average which result in the transmissivity being 40% lower than average. Multivariable attribute analysis was later used to improve the porosity-amplitude correlation, and these results are discussed later in the report.

Reservoir Modeling

Structure and isopach maps were loaded into Landmark's Stratamodel. program, and a preliminary 3-D geological layer model was developed. Digitized maps of the interpreted horizons ("J", "K", "K-2," "L", and the top of the Bone Spring formation) were imported into SGM to create a stratigraphic framework model of the NDP. Initially, both the "K" and "L" sandstones were divided into four sub-units. The sandstones were correlated laterally from well to well in the NDP. Gross isopach, net porosity isopach and log-derived net pay maps were constructed for each of the sub-units of the "K" and "L" sands as well as the "K-2" and "J" sands. The maps were contoured to conform to the overall gross interval isopach maps for the respective pay zones that were used to construct the geological model. Since the producing zones and subzones were relatively thin, great care had to be exercised to prevent intersections of the horizons. It was also critical that the surfaces tie to the well picks of the lithological markers in the well traces. In general, the most successful approach to this problem was based on the use of gross isopach thickness interpretations building from the structural top of the Bone Springs Formation up to the structural top of the "J" sandstone.

The next major step was the development of a well attribute model. This activity was supported by the engineering database. For each of the 17 NDP wells, the following attributes were imported into the well model: neutron porosity and gamma ray, interpreted porosity and permeability, perforated interval and fractured interval, net pay, and water saturation. In some instances, these attributes were available on a foot-by-foot basis for one or more of the producing zones. Not all of the attributes were available for each well. For reservoir simulation, the most important reservoir attributes are fluid conductivity and rock matrix storage capacity. The distributions of these properties throughout the NDP were based on the well attribute model. Within SGM, these distributions were interpolated deterministically, that is, weighted by the reciprocal of the square of the distance between the location of interest and nearby wells in the reservoir model.

The structural relationship between the five major producing horizons in the NDP is illustrated in **Fig. 12**. The step-bench sequence is a typical depositional characteristic of the basal Delaware zones in this area. Typical benches are 0.8 to 1.6 km (0.5 to 1.0 mile) wide with dip rates of 0.8% to 1.9%. Typical steps are 0.4 to 0.8 km (0.25 mile to 0.5 mile) wide with dip rates of 3.3% to

8.0%. Better producing wells are located on the benches and poorer producers are located on the steps in the NDP as well as in nearby Delaware fields.[2]

Detailed mapping of the reservoir engineering data along with the geological data revealed the complex nature of these Brushy Canyon sands. Each of the three primary reservoir sands in the study was mapped using a variety of parameters. In the NDP, there appears to be three primary depositional fairways in the “L” sand in which the better reservoir quality rock has been developed. Net porosity maps combined with log-derived net pay and capillary pressure data were integrated and support this interpretation. Comparing isopressure maps, there appeared to be a correlation between pressure distribution and the distribution of sand in the lobes of the “L” sand complex. If these sands were more uniform or laterally continuous, then we would expect to see a more gradational and uniform change in pressure following the east-to-west change in structural dip. The pressure distribution along with the geological interpretation suggested that these reservoirs were more compartmentalized than initially believed. The “K” sand was laterally segregated into two primary depositional lobes in the same manner as the “L” sand.

After the 3-D seismic dataset was interpreted, it became apparent that the original conception of the NDP as a collection of thin channel sands continuously distributed between wells was incorrect. In particular, on the basis of the interpreted seismic amplitude data, the area around the proposed pilot centered at NDP Well #1 was reduced to a "lobe" of approximately 300 acres (121 hectares) containing NDP Wells #1, #5, #6, #10, and #14[16,17]. Moreover, the interpreted seismic data indicated that the NDP may be highly compartmentalized, and that some of the compartments, for some sand sequences in the “L” zone, may be much smaller than 300 acres (121 hectares).

Analysis of the instantaneous frequency displays, seismic volume, and pressure data indicated parts of the “K” and “L” reservoirs are compartmentalized (see **Fig. 13**). Instantaneous frequency volumes were calculated from the NDP 3-D data, and the instantaneous frequency behavior was then interpreted across several chronostratigraphic horizons passing through the “K” and “L” reservoir sequences. Using these interpretations, a tentative reservoir compartment model was developed for the “K” sequence across the NDP. This tentative compartment map indicates there are large compartments around the better producing wells (e.g., NDP Wells #11, #15, and #19) and segmented compartments near the poorer producers (e.g., NDP Wells #5, #6, and #25).

Over the course of the first year of the project, three “generations” of geological models were developed based on evolving interpretations of the structure of the NDP. In the first generation, a full NDP model was developed from the initially-available geological interpretation based on logs and cores. The second generation model was based on these data plus newly-interpreted pressure transient data. The third version reflected a geological interpretation, based on the 3-D seismic data that indicated there is considerable compartmentalization within the NDP. The integration of the log, core, and pressure transient data led to an interpretation of the NDP with three non-communicating lobes of oil. The proposed pilot injection area was confined to one of these lobes.

Simulation Model of the Pilot Area

A detailed reservoir model of the "L" sand in the proposed pilot injection area (which contains the oil lobe supporting the pilot) was developed for reservoir simulation studies. The model of this compartment contained NDP Wells #1, #5, #6, #10, and #14. Since approximately 90% of the oil produced from the five wells in this lobe can be traced back to the "L" zone (see **Fig. 6**), only this zone was included in the simulation model studies. Reservoir attributes including porosity, relative permeability, and oil and water saturations were distributed vertically and laterally throughout the layers in the simulation model. With the exception of compartment boundaries, the distribution of reservoir storage and conductivity was based on the petrophysical interpretation cited earlier. Because of the highly lenticular distribution of oil within the four subzones identified in the "L" zone, a twenty layer simulation model (**Fig. 14**) was chosen for the pilot area; that is, five proportional layers for each of the La, Lb, Lc, and Ld subzones. This resolution was the minimum required to capture the nature of the thin beds of the sandstones in the "L" zone.

Each layer of this 20-layer model had approximately 300 uniform cells that were 67.1 m (220 ft) on an edge. The unusually high definition in the vertical dimension was necessary to capture the lenticular distribution of oil within the four subzones of the "L" sand. The distributions of porosity and water saturation are shown in **Figs. 15 and 16**, respectively. These figures illustrate the highly lenticular nature of the Brushy Canyon sandstones in the NDP pilot area.

Pilot Area Reservoir Simulation Studies

A reservoir simulation model for the pilot area envisioned that a single well in the pilot area would be converted to injector status to test the efficacy of injecting water, lean gas (immiscible), and/or CO_2 (immiscible or miscible) to improve oil recovery at the NDP. Eclipse 100® was used for the immiscible hydrocarbon gas cases and VIP-COMP® for the CO_2 cases. However, the reservoir description was the same for all forecasts, and was based on the history match obtained with Eclipse 100®. The following tasks were required to complete the pilot simulation phase: possible scale-up of lithological units, interpolation of geological attributes on the simulation grid, validation of pilot simulation model, and design and execution of prediction cases.

Model Validation Criteria

Our criteria for a "good" match of historical performance were reasonable agreement between simulated values and actual values of the following: drainage-area average pressure for each well (as determined by analytical methods), oil production by well, water production by well, gas production by well, and onset of pumping conditions.

Oil production, by well, was used as the driving function for the simulations. Consequently, it would be expected that oil rates were honored exactly by the simulations. However, all five of the Nash Draw wells in the pilot area node reached pumping conditions during the validation step of this project. When a simulated well reaches pumping conditions, the oil rate is not necessarily honored by the simulator, and the oil rate itself becomes a history matching parameter. In this case the bottomhole pressure became the driving function.

A good match of drainage area pressure, water production and gas production for each of the wells was obtained for the three and a half years of production from this compartment.

Waterflood Predictions

Reservoir simulation results[2] indicated that the permeabilities of the Brushy Canyon sandstones are probably too low for waterflooding to be effective. Calculations of water injection rates indicate that the water injection rates would be 150 to 200 barrels of water per day, which would be too low to obtain response in a reasonable length of time. Thus, the simulation forecasts focused on enhanced recovery options.

Enhanced Recovery Forecasts

Forecasts were made for two possible enhanced recovery scenarios: immiscible gas (both hydrocarbon and CO_2) injection and miscible CO_2 injection. Details of the reservoir simulation studies are presented elsewhere.[2,3]

Immiscible Lean Gas Injection

Two cases were investigated for the injection of hydrocarbon gas:[2]

Case 1: Conversion of NDP Well #1 to a gas injector on March 1, 1997 (this corresponded to the date of the most recent production data available at the time the study was conducted), and

Case 2: Conversion of NDP Well #1 to a gas injector on October 1, 1993, one year after production in the pilot area started.

In Case 1, the premise of this forecast was simple: NDP Well #1 was converted from an oil producer to a gas injector after the pilot area had produced to the time of the simulation. The forecast was run for two years. NDP Well #1 injected against a flowing bottomhole pressure (fbhp) constraint of 20,684 kPa (3000 psi), the largest pressure entry in our PVT table. The pressure in the drainage region of NDP Well #1 did respond to gas injection as anticipated. However, the pressure response for the remaining four producers in the pilot area was not very encouraging. Gas breakthrough occurred in NDP Well #5, the well nearest NDP Well #1, after about a year, and this well was shut in, since the large fracture mitigated against a workover.

The premise for Case 2 was the idea that the injection of gas early after the onset of production might avoid the channeling of gas through zones of free gas that existed in Case 1. For this case, NDP Well #1 was converted to gas injection after only one year of production. The average pressure in its drainage region was still around 11,721 kPa (1700 psi), and above 17,237 kPa (2500 psi) in the drainage areas of the other wells in the pilot node. As in Case 1, the fbhp was 20,684 kPa (3000 psi) for NDP Well #1. The pressure response for NDP Well #6, unlike Case 1, experienced an increase in pressure during the period of the forecast. Oil production rates reached a high plateau followed by a gradual decline.

Because the pilot area was the most developed area of the NDP, this area had a greater well density and the wells in this area had been producing for a longer period of time. Consequently, there was very little natural energy left in the pilot node at the inception of injection, and any fractures or zones with free gas would provide a ready conduit for early breakthrough of injected gas. The simulation results indicated that implementation of a gas injection pressure maintenance scheme after the drainage area pressures had declined below 3447 kPa (500 psi) would not be successful in improving oil recovery. Even for higher initial drainage area pressures around 10,342 kPa (1500 psi), the simulation studies indicated that immiscible gas injection would be of marginal value. On the other hand, the implementation of pressure maintenance, specifically gas injection, early in the development of the pattern could have doubled the recovery of oil in the five-spot pattern during the early years of production. Immiscible gas injection at pressures above 17,237 kPa (2500 psi) might lead to the recovery of enough additional oil to merit at look at economics.

Forecasts of Immiscible Injection

Simulation forecasts[2] indicated that neither immiscible gas nor water injection into NDP Well #1 would measurably improve the recovery from the surrounding wells (e.g. NDP Wells #5, #6, #10, and #14). It appeared that pressure maintenance, preferably with gas due to the tightness of the formation, would have had to have begun almost immediately after the first oil was produced from the compartment to have had much of an effect. Hence, immiscible gas injection may be viable if initiated early and if undeveloped regions of the field can be found that have not been pressure depleted.

Carbon Dioxide Injection

Although a different reservoir simulator was required for the CO_2 injection study,[3] the history match in the pilot area for the CO_2 cases was qualitatively the same as that obtained for the hydrocarbon gas study. History match for gas production from the five wells in the pilot area (NDP Wells #1, 5, 6, 10, and 14) show typical solution-gas-drive performance with initial high gas-oil ratios (GORs) decreasing as the reservoir is depleted. Since the pilot location for this study was no longer under consideration for the field trial, further history matching was not performed, since it was likely only minor differences in results would follow. Instead, several predictions for CO_2 injection were performed to obtain qualitative results for this recovery process.

Several prediction simulations were performed with CO_2 for both miscible and immiscible injection scenarios. For the miscible injection cases, simplifying assumptions were made because no laboratory data were available. In particular, the miscible injectant was assumed to have properties of pure carbon dioxide and to be first-contact miscible with the reservoir oil. To compare the different prediction cases, oil production was calibrated by adjusting the flowing bottomhole pressure at the beginning of the prediction cases so that the oil production rate was similar to the field-observed rates. With the constant bottomhole pressure as a boundary condition, predictions were then made from the end of history for 11 years to March 2008. Injection was assumed to begin immediately after the end of the history match, although in reality a delay of at least 2 years would be required for project implementation. Injection was based on 120 MSCF/D of gas injectant - either miscible or immiscible. This volume was based on the volume of immicible gas required to maintain pressure in the reservoir. A water-alternating-gas (WAG) scenario was also simulated. In this case the injection bottomhole pressure was limited to 34,474 kPa (5000 psi) with a WAG ratio of about 4:1 water to carbon dioxide.

Simulations compared a base case of continued operations with no injection to a total of 9 prediction cases for various recovery scenarios: (1) convert NDP # 1 to injector - 120 MSCF/D CO_2 miscible, (2) convert NDP # 5 to injector - 120 MSCF/D CO_2 miscible, (3) convert NDP # 6 to injector - 120 MSCF/D CO_2 miscible, (4) convert NDP # 10 to injector - 120 MSCF/D CO_2 miscible, (5) convert NDP # 14 to injector - 120 MSCF/D CO_2 miscible, (6) infill injector - 120 MSCF/D CO_2 miscible, (7) infill injector - 4:1 WAG, (8) infill injector - 60 MSCF/D CO_2 miscible, and (9) infill injector - 120 MSCF/D immiscible injection. The infill injector was located at the center of the pilot area between wells NDP # 1, 6, 10, and 14.

Forecasts of CO_2 Injection

Simulation results for miscible injection in the NDP pilot area indicated that carbon dioxide injection could be a viable alternative for improved oil recovery for this field if an economical source of CO_2 had been available. For the eight different CO_2 miscible scenarios, incremental oil recoveries ranged from a low of 40 MSTB to a high of 110 MSTB (**Table 5**). Compared to a continued operations case, increased oil recovery in the range of 2 to 5% of original-oil-in-place was observed during the ten years of the forecast. CO_2 injection, if implemented before the pressure has declined below about 10,342 kPa (1500 psi), might be successful but economics of the process would need to be evaluated. Thus, areas of the field already under production may be candidates for CO_2 injection if pressures have not declined too much. However, immiscible CO_2 injection did not produce significant oil production in the simulation forecasts.

These results coupled with a reasonable recovery per thousand cubic feet (MCF) of CO_2 injected indicate that further investigations could be made into CO_2 miscible injection, but a source of low-cost CO_2 was not available in the immediate vicinity of the NDP.

Reservoir Compartments and Boundaries

Analysis of the instantaneous frequency displays, seismic volume, production interference, and pressure data indicated that parts of the "K" and "L" reservoirs are compartmentalized. For the NDP 3-D seismic data, any frequency component calculated from the data that falls outside the range 0 to 120 Hz (the highest frequency created by the vibrators) is, by definition, an anomalous frequency value. When 3-D seismic data volumes are converted into 3-D volumes of instantaneous frequency, there are always a large number of anomalous frequency values.

Instantaneous frequency volumes were calculated from the NDP 3-D data, and the instantaneous frequency behavior was then interpreted across several chronostratigraphic horizons passing through the "K" and "L" reservoir sequences. Using these interpretations, a reservoir compartment model was developed for the "K" sequence across the NDP. This compartment map is realistic in the sense that it indicates there are large compartments around the better producing wells (e.g., NDP Wells 11, 15, and 19) and segmented compartments at the poorer producers (e.g., NDP Wells 5, 6, and 25). Production modeling confirmed that the compartment sizes and shapes suggested by this model were realistic.

Further work was done in the Brushy Canyon "L" zone to compare the correlation of the boundaries between the observed data. A strong correlation was seen between production and testing analysis, seismic interpretation, and the geostatistics/seismic attribute analysis. These data were refined to predict drainage areas and depositional trends.

Drainage Areas

To estimate drainage areas for each well, decline curves were extrapolated to predict the ultimate oil recovery from each well, and this value was divided by the oil recovery per acre. The calculated drainage area (see **Table 6**) was then adjusted depending on the seismic amplitude in the "L" zone.

The seismic amplitude coincided with areas that are compartmentalized or continuous. Negative amplitudes of 0 to -20 were associated with areas that are compartmentalized, and areas with negative amplitudes from -20 to -60 were in areas where the zones were more continuous. Analysis of the areas that were compartmentalized indicated that approximately 60% to 75% of the pay interval was continuous enough to contribute to production. The drainage areas associated with these wells were multiplied by a factor of 1.33 to adjust for zones that were not continuous, and this yielded an indicated drainage area.

By comparing the indicated drainage area to the drainage area that the well was predicted to drain (based on governmental proration units or stimulation designs) a drainage ratio "D" was calculated. If the wells were effectively draining the area they were designed to drain, the drainage ratio should be 1.0. The drainage ratios ranged from 0.15 to 1.23, with 53% ranging from 0.75 to 1.25.

The other factor influencing oil recovery is interference from offset wells and the resulting depletion. Depletion was evidenced by initial gas-oil-ratios (GORs) that are above 2,000 SCFG/BO. The initial wells and wells drilled away from developed areas had initial GORs of less than 2,000, and wells drilled in developed areas or later in the development of the field had GORs of 2,000-14,000 to 1.

This resulted in the early wells, such as NDP Wells #1, #11 and #13, recovering more oil than predicted and later wells such as NDP Wells #12, #29 and #38 recovering less oil than predicted. A strong correlation was found between the transmissibility (kh/μ), the number of sacks of sand used in the frac treatment, and the ultimate recovery. The ultimate recovery was approximated by the following relationship:

$$BO = ((kh/\mu) \times \text{No. Sx. Sand})^{.5} \times 1{,}000 \qquad (7)$$

A closer correlation was obtained by adding the drainage ratio to the equation to obtain:

$$BO = ((kh/\mu) \times \text{No. Sx. Sand})^{.5} \times \text{Drainage Ratio} \times 1{,}000 \qquad (8)$$

Ultimate recoveries, GORs, volumes of sand, and drainage ratios are given in **Table 6** for each of the NDP wells.

Reservoir Compartments

The analysis of reservoir, seismic, and production data led to an interpretation of the major reservoir compartments in the "L" Zone. Using a reservoir simulator model to match gas/oil ratio (GOR) history and to estimate reservoir pressure, bottomhole pressure (BHP) history was developed for each well (see the BHP/GOR model results shown in **Table 7**).

The BHP data were then used in a nearest-neighbor analysis to determine areas of the reservoir with common pressure characteristics. The nearest neighbor analysis coupled with the cumulative production vs. rate analysis and the geostatistical analysis (described later in this report) have provided an interpretation of the major reservoir compartments in the "L" Zone.

This interpretation indicated a series of well defined compartments that were identified by production interference, seismic data, and pressure history. These major compartments are shown in **Fig. 17** and are summarized in **Table 8.** There is good correlation of the boundaries between the observed data and the seismic interpretation. Boundaries were interpreted to exist where there was a large contrast in amplitudes, from a high negative amplitude area to a low negative amplitude area. This interpretation was supported by the analysis of instantaneous frequencies discussed earlier in the section on Reservoir Modeling and summarized in **Fig. 13**. The previous interpretation indicated compartments that were more complex than this interpretation, but may be more accurate in the light of reduced recovery efficiency of wells in areas earlier described as "highly compartmentalized." This may indicate that some individual sands are continuous from well to well and some sands are very limited in aerial extent.

Geostatistics and Analysis of Seismic Attributes

Early in the project, results of the "L" zone amplitude-porosity correlations[2] were used to locate NDP Well #29. Because the porosity encountered in Well #29 was 40% less than that predicted from correlation, two different approaches were investigated to forecast spacial reservoir properties. A production interference analysis was conducted to define flow units, and several mapping techniques were used to describe the static reservoir properties.

Well Interference and Flow Units

Oil rate versus cumulative production curves were reviewed for evidence of interference resulting from the production from newly completed off-set producing wells. The wells were assigned to the flow units based on a slope change and the initial GOR. A high initial GOR with a constant slope indicated that pressure depletion had occurred at the time of completion. In this case, flow units were defined as areas exempt from interference from off-set wells. Following is a summary of this analysis:[2]

- Wells drilled on 40-acre spacing exhibited interference
- Pressure depletion can occur over distances greater than 488 m (1600 ft).
- Some wells exhibited little or no effects of interference—this could be attributed either to compartmentalization or to a large reservoir volume in relation to the amount of interference.
- Wells drilled on 40-acre spacing may have recovered less than 60% of the recoverable oil due to the laminated and discontinuous nature of the reservoir.

Statistical Analysis of Flow Units

Several mapping techniques were used to describe the spatial distribution of the “L” zone static reservoir properties. Since the objective was to optimize the placement of drilling locations, the hydrocarbon pore volume ($h\phi S_o$) was the reservoir mapping parameter. The $h\phi S_o$ parameter was developed from log information and was mapped with a conventional, nearest neighbor ($1/r^2$) technique, with a kriging technique based on a spherical variogram model, and with a fractal model. The maps resulting from the three different methods were similar,[3] and only the fractal map is presented in this report (see **Fig. 18**).

In addition to the static reservoir properties, a “drill here” map also requires an estimate of bottomhole pressure. Estimates of the distribution of dynamic reservoir properties such as pressure, best obtained by matching the past reservoir history with a simulator, were reported in the second annual report.[2] Bottomhole pressure was estimated based on the producing GOR data and PVT data. These estimates were normalized with the 20,340 kPa (2950 psi) discovery pressure and then used to calculate $h\phi S_o(p/p_i)$. These values were used to generate the fractal map in **Fig. 19.** The delineation of the flow units coupled with the hydrocarbon pore volume/BHP map suggested that future primary development should be towards the northwest under the playa lakes.

Geostatistics and Interwell Properties

In an effort to better define interwell properties and to understand the reservoir northwest of the current producing wells, two geostatistical analyses were conducted. The first focused on extrapolating with the variogram developed from well data to an area northwest of NDP Well #13. The second was a scoping study applying ordinary kriging to slices from the 3-D seismic survey in order to estimate the density of 2-D lines required to capture the features apparent in the 3-D grid.

Geostatistical Extrapolation

Interwell reservoir properties were estimated with three different mapping techniques: a conventional nearest neighbor ($1/r^2$) method, a kriging method, and a fractal algorithm. The net thickness, porosity, and oil saturation arithmetic average values for the “K” zone and the “L” zone were determined from analysis of well logs. The interpolated porosity values between the wells showed that the basic pattern provided by the three mapping methods was similar for the "L" zone while the "K" zone was less similar.

A low correlation coefficient for interwell properties provides little help in selecting future vertical well locations based on hydrocarbon pore volume (HCPV) maps. If the correlation coefficient was better than 16%, these mapping techniques could be used as a method to select vertical well drilling locations with some confidence. The unknown effect of free gas saturation (pressure) on estimating oil saturation could be a cause of the poor correlation coefficient. Multivariate analytical tools, described later in this report, were investigated as a means of correlating 3-D seismic attributes with the same well properties as used in this geostatistical study.

2-D Seismic Analysis

The purpose of this geostatistical research was to gain insight into the density of 2-D seismic lines required to identify reservoir features that are present in the 3-D data set. An experimental 2-D data set was constructed from the NDP 3-D survey, and the density of the 2-D slices was increased in order to capture many of the original features of the 3-D survey. The example visually demonstrated the potential to identify reservoir features with multiple 2-D datasets. Details of this analysis can be found elsewhere.[3]

3-D Seismic Attribute Analysis

Because the NDP wells primarily cover the center part of the available seismic survey, a methodology was tested for relating reservoir properties at the wellbore to sets of seismic attributes in order to extrapolate reservoir properties beyond the area directly constrained by wells and to predict reservoir properties across the whole field. Seismic attributes have recently been the focus of renewed interest for evaluating reservoir properties. Well data gives very precise information on the reservoir properties at specific field locations with a high degree of vertical resolution, while 3-D seismic surveys can cover large areas of the field, yet reservoir properties are not directly observable, in part due to relatively poor vertical resolution.

A new technique was developed that utilized a non-linear multivariable regression to correlate statistically selected seismic attributes to reservoir properties (porosity, water saturation, and net pay). The new technique used seismic attributes as inputs with porosity, water saturation, and net pay as outputs. The regression equations allowed a prediction of these three reservoir properties in areas without direct well control. Mathematical relationships between the attributes and wellbore parameters from wireline logs were established, and maps of reservoir properties were computed for the location of each seismic bin, every 33.5 m (110 ft), across the NDP for the "K" and "L" intervals.

Data Sources

The two primary sources of data required for this method are well data and seismic attribute data. Over 80 seismic attributes were extracted from the NDP seismic data volume for the two horizons using the PostStack® and Pal® tools of the Landmark Graphics seismic interpretation suite. Extracted attributes were averaged across the entire interval of both the "K" and "L" horizons, respectively, and the well data from each of the 19 wells used in the study were also averaged across the respective intervals. Thus the output maps presented later in this report represent interval-averaged values for the respective reservoir properties.

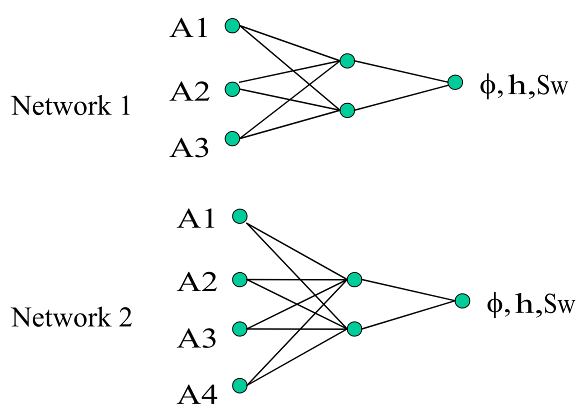
Attribute Selection

It is computationally infeasible to use all of the extracted attributes in individual non-linear regressions for reservoir properties; therefore a fuzzy-ranking algorithm[31] was used to select attributes best suited for predicting individual reservoir properties. The algorithm statistically determines how well a particular input (seismic attribute) could resolve a particular output (reservoir property at the wellbore) with respect to any number of other inputs. Each attribute is assigned a rank, which allows a direct estimation of which attributes would contribute the most to a particular regression.

The fuzzy ranking algorithm was applied to select the optimal inputs (attributes) for six output cases: "K" porosity, "K" net pay, "K" water saturation, "L" porosity, "L" net pay, and "L" water saturation.

Multivariable Non-Linear Regression

Linear regression for reservoir properties was not feasible for this study, as the relationships between input and outputs were poorly defined by individual attributes. We elected to use a non-linear regression using the fast-converging, feed-forward, back-propagation conjugate gradient algorithm (neural network) implemented in-house at the PRRC. Two neural network architectures were used in the study, both of which were minimized in order to maintain a satisfactory ratio of training data to weights (coefficients of the regression equation). The two networks are graphically illustrated below.



In these architectures, circles represent "neurons" or locations of non-linear functions, while each line represents a coefficient applied to these equations. A back-propagation feed-forward algorithm, such as the conjugate gradient algorithm used, is "trained" using known inputs and outputs. For this study, reservoir properties were known at the locations of the wellbore intersections with the interval of interest. Seismic attribute data from the same seismic bin that contained the well was correlated to wellbore values of porosity, net pay, or water saturation in an iterative process using the neural network.

Training and Testing

It is customary to test the robustness of a solution by holding some data out for testing. Since only 19 control points were available, the networks were trained using all 19 points, and then tested by removing sets of three wells, retraining the network with 16 control points, and then using that network to predict the three withheld points. This exercise was applied three times for each property and interval, withholding differing sets of three points for each test. Results of the training with all 19 points, and three test sets for the "L" interval porosity regression, showed that the network resolved porosity in a robust fashion, and that the tool could be used to predict porosity in other areas of the field (see **Fig. 20**). The 19 point networks for the other reservoir properties of the "L" and the "K" intervals are shown in **Fig. 21**. These regressions were also tested in the same manner and had similar results.

From the Fuzzy Ranking and non-linear multivariable regression evaluation of seismic attributes, the key reservoir properties were estimated. The porosity evaluation used the isochron, instantaneous frequency, and energy half-time attributes as inputs, and the resulting neural network trained to a correlation coefficient (cc) of 0.88. The water saturation evaluation trained to cc=0.84 and used the instantaneous phase, average trough amplitude, and energy half-time attributes. The net pay evaluation used the maximum peak amplitude, RMS amplitude, and peak amplitude attributes and trained to cc=0.80. In each case, the output data used for training was a reservoir property, porosity, water saturation, or net pay, from 19 wells in and adjacent to the NDP.

Predicting Fieldwide Reservoir Properties

The regression relationships (architecture and weights) were used to compute maps of fieldwide porosity, net pay, and water saturation, which were displayed in Landmark's SuperSeisworks Map view. In general these maps fit expectations based on other geostatistical techniques and reservoir understanding. Net pay, porosity, and water saturation maps were generated using the regression relationships and seismic attributes at each seismic bin location. Maps of ϕh and $h\phi S_o$ computed from those reservoir property maps provided a detailed estimate of interwell and field-wide oil pore volume at the NDP. The techniques that were developed maximize both the well control and seismic data and generated useful maps for targeted drilling programs in the field.

From the "K" and "L" interval porosity maps predicted using the regression relationships, both the "K" and "L" horizons showed patterns of distinct or isolated porosity, and the "L" porosity map compared favorably with compartment maps produced independently. From the "K" and "L" interval net pay maps, the "K" horizon showed much more variation in pay than the "L" zone, which is reasonable considering that the "K" interval is discontinuous and may pinch out, while the "L" interval is considered to be reasonably continuous across the study area. Lineations in the NW corner of the "L" net pay map may indicate facies changes or onlap deposition and

subsequent compartmentalization. From the “K” and “L” interval water saturation maps, the “K” interval appeared to very water wet except in distinct pods which may represent possible drilling targets. The “L” interval appeared to be wet in a more uniform fashion; however an area of high water saturation in the NW corner, which is up-dip, may be due to compartmentalization.
The ϕh maps were useful as an indicator of where sufficient pay porosity exists within the field. The “K” horizon showed a good deal of variability with relatively lower ϕh in areas where the “K” zone is interpreted to pinch out. The “L” interval ϕh showed a more uniform distribution of pay porosity although some thinner and thicker areas did exist. The hydrocarbon pore volume maps for the “K” and “L” intervals include information on oil saturation ($1-S_w$) and essentially illustrates where the oil may be located in the field. The water wet “K” interval showed only isolated pods of good production potential, while the less wet “L” interval (see **Fig. 22**) showed strong undrilled potential production in the SE quadrant of Section 11, the SW and NW quadrants of Section 7, and the west half of Section 14. Areas to avoid drilling for the “L” interval might include the east half of Sections 7 and 18, the SW quadrant of Section 13, the SE quadrant of Section 14 and the northern half of Section 11.

These results suggest that it may be possible to predict interwell and fieldwide reservoir properties from a geostatistical analysis of seismic attributes using fuzzy logic and neural networks. Details of the technique are presented elsewhere,[3,18] and further extensions of the technology are available in the literature.[19-24]

Deviation from Original Plan

The proposed pilot area around NDP Well # 1—including NDP Wells #l, #6, #14, #5, #9, and #10—was reconsidered as a result of the characterization studies. Comparison of the seismic data and engineering data showed some evidence of discontinuities in the area surrounding NDP Well #1. Analysis of the 3-D seismic showed that these wells are in an area of poor quality amplitude development. The implication is that since amplitude attenuation is a function of porosity, then this is not the best area to be attempting a pilot pressure maintenance project. A comparison of estimated ultimate recovery (EUR) figures from these wells to wells in areas having better quality reflection amplitudes showed that these were some of the lowest EUR wells in the field. The better wells correlated with the better quality amplitude anomalies which corresponded to higher EUR figures. Because the original pilot area appeared to be compartmentalized, the lateral continuity between the pilot wells could be reduced. Therefore, the focus of the implementation phase of the project shifted more to targeted drilling and recompletion of uphole zones.

Conclusions from the Science Phase

An extensive database of new geological, geophysical, and engineering data for the Delaware formation was compiled that can be of interest to companies operating in similar reservoirs. Producing companies and consultants working in the area can extend the data and interpretations to other Delaware reservoirs. Because of the complex distribution of the Delaware sands, the principles learned at the NDP can be applied to other Delaware Pools to help reduce the lead time and shorten the learning curve associated with implementing reservoir management strategies to maximize recoveries. Following is a summary of the results of the studies conducted in Phase I, the Science Phase of the NDP project:

Geological Analysis

- The faults and depositional character of the deeper structures (Morrow and Bone Spring) provided the depositional surface for the shallower sequences and created the bench-step surface being used to describe the Brushy Canyon reservoir.

- The Brushy Canyon reservoir at the NDP is much more complex than initially indicated by conventional geological analysis. While the original concept pictured the NDP as a collection of thin channel sands continuously distributed between wells, the results from Phase I show the subzones within the sandstones are lenticular and are not always continuous from well to well which can affect flow paths between wells.

- The interpretations of the advanced reservoir analysis show the oil accumulation in Brushy Canyon interval exists areally as pods or fairways and vertically as stacked micro-reservoirs.

- Examination of the core under ultraviolet light revealed the discontinuous character of the hydrocarbon distribution mixed with water zones throughout the pay interval. This correlates with the erratic vertical distribution of oil and water saturations calculated from the log analysis.

Advanced Core-Calibrated Log Analysis

- To evaluate the highly laminated micro-reservoirs that make up the pay zones in the Brushy Canyon interval, a log evaluation technique was developed to identify pay that is laminated with wet zones. The methodology for identifying net pay in complex reservoirs can be applied in other sandstone formations that are highly laminated.

- By properly identifying productive pay intervals, oil recovery from the Brushy Canyon reservoir at the NDP was calculated to be 16.6%, rather than the 10% as initially estimated.

- Although the original evaluation suggested that both the “K” and “L” sandstones were the major oil producing intervals, the results of Phase I showed that the “L” sandstone was the primary oil productive zone at the NDP.

- Using transmissibility values to calculate production from the various zones for 16 wells in the NDP, results showed that while the bulk of the oil production at the NDP comes from the “L” sandstone, much of the water is produced from the “K” and “K-2" sandstone, if the latter zone is present.

Geophysical Results

- By conducting pre-survey VSP wave testing and by careful processing of 3-D seismic data, the thin-bed turbidite reservoirs at the NDP were imaged, and the individual Brushy Canyon sandstones at the NDP could be resolved.

- The interpreted seismic data indicated that the NDP is highly compartmentalized, and that some of the compartments, for some sand sequences in the "L" zone, may be much smaller than 300 acres.

- Results suggest that interpretations of the seismic data can be used for targeted drilling in high-grade areas of the NDP that are not accessible with vertical wells.

Reservoir Simulation

- Immiscible gas injection for pressure maintenance in the proposed pilot area at the NDP was ruled out because of low reservoir pressure and compartmentalization of productive intervals.

- The low permeabilities and relative permeability effects precluded waterflooding at the NDP.

- Miscible CO_2 flooding could be a viable method at the NDP, but a low-cost source of the gas was not available in the vicinity of the NDP.

- Injection of immiscible hydrocarbon gas for pressure maintenance could be viable in undeveloped regions if those areas are not pressure depleted or compartmentalized and if injection is initiated early.

Geostatistics and Seismic Attribute Analysis

- Fuzzy Ranking can help decide which seismic attributes are most useful for evaluating reservoir properties.

- Multivariable non-linear regression (Neural Networks) were used at the NDP project to correlate well and seismic data with the goal of predicting interwell reservoir properties and extrapolating to regions beyond well control.

Well Completion, Stimulation, and Workovers

- A detailed characterization of the reservoir provided an accurate model to predict completion and development scenarios. In future wells, only zones with commercial quantities of hydrocarbons can be completed, fracture heights can be predicted, and well spacing and completions can be optimized.

- Results of the integrated reservoir characterization efforts provided a basis for using combinations of deviated and horizontal wells combined with selective zone completions to improve production performance at the NDP in the implementation phase of the project.

Plans for the Implementation Phase of the Project

Phase II of the NDP project was directed toward enhancing the ultimate recovery from the Brushy Canyon reservoir. The plans included: (1) evaluation of prospects of early pressure maintenance, (2) well workovers of existing vertical wells to tap into behind pipe reserves, and (3) drilling of new directional/horizontal wells in order to develop reserves under surface-restricted areas and potash mines.

Gas Processing and Injection

Early in the second phase of the project, a study was undertaken to evaluate the design and economics of processing the gas at the NDP to recover liquids and reinject lean gas for pressure maintenance. The study[7,8] indicated that stable gas volumes of 3 million cubic feet of gas per day (MMCFGD) or larger would be economic to process. Recovery of liquids from a -10^{o} F plant would be 4.1 gal/MCFG of the available 6.1 gal/MCFG that was available at the time of the study.

The study and preliminary design indicated the cost of the gas plant to be $957,000 and the cost of compression to be $1,000,000. These estimates could have varied as much as 25% depending on the availability of equipment.

The future estimated gross oil and gross gas, as well as undiscounted and discounted net cash flow (NCF), were calculated for conventional sales (Case 1) and for processing and reinjection (Case 2). An analysis was completed of the economic impact of gas processing and reinjection for pressure maintenance versus gas sales using the existing gas contract. Results are presented in **Table 9**.

Case 1 resulted in 459,849 BO less oil production but 1,009,277 MCF more gas production than Case 2. The reinjection of gas assumed in Case 2 resulted in higher oil recoveries but less gas recovery. This was due to the inability to economically recover all of the gas that was injected; approximately 25% of the injected gas was estimated to be unrecoverable or lost.

Case 1 resulted in $5,270,155 less NCF than did Case 2. Despite the lower gas production in Case 2, the higher oil production produced more profit. However, when the Case 1 and Case 2 NCF were discounted, the difference was only $37,566. This difference was partially due to the delay of increased oil production as a result of Case 2 gas injection. Primarily, however, most of the difference was due to the delay of recovery and sale the reinjected gas volumes. These gas revenues were not received until 2020 to 2022, very near the economic end of the project.

Based upon this analysis, the best economic course was to continue to sell the gas outright to the purchaser as evidenced by the results of Case 1. The additional capital cost required to install the Case 2 processing and injection facility was not justified given the estimated future profit. However, if a processing and reinjection system had been installed near the beginning of the NDP project some ten years ago, the increased oil and gas production volumes would have made better economic sense. The NDP had produced in excess of 1.25 million BO and 7.2 BCFG at the time this study was done. These volumes, together with increased oil recoveries from pressure maintenance, may have allowed a more rapid return and an ultimately higher multiple on the gas processing and injection facilities

Well Workovers

To develop additional reserves at low costs, zones behind pipe in existing wells were evaluated using techniques developed for the Brushy Canyon interval. The Advanced Log Analysis technique developed in Phase I was used to complete uphole zones in a total of thirteen NDP wells. Four wells (NDP Wells #13, #15, #19, and #24) were recompleted in 1999, which resulted in the addition of reserves of 73,842 BO and 36,921 MCFG. This allowed the development of economical reserves during a period of low crude oil prices and encouraged the continued use of the technique. An additional four wells (NDP Wells #5, #6, #11, and #23) were recompleted during 2000, which resulted in 123,462 BO and 453,424 MCFG reserves being added at a development cost of $1.57 per barrel of oil equivalent (BOE). Two wells, NDP Wells #29 and #38, were recompleted in 2001 which added 7,000 BO and 18 million cubic feet of gas (MMCFG) to the reserves at a cost of $9.70 per BOE. During 2002-2003, NDP Wells #1, #12, #15, and #20 were recompleted in uphole zones which added 128,000 BO and 150 MMCFG to the reserves at a cost of $1.65 per BOE. Total reserves added from the workover of vertical wells at the NDP were 332,304 BO and 640,363 MCFG. Overall, the weighted average development cost of workovers at the NDP was $1.87 per BOE.

Additional 3-D Seismic Survey

A new 3-D seismic survey was designed for the north end of the NDP where the original 3-D survey indicated that oil and gas reserves were located in potash mining areas or under playa lakes. These reserves were beyond the regions covered by well control and were not accessible with vertical wellbores. Results of the new survey were aimed at identifying undrained areas which were not pressure depleted or "sweet spot" regions of the reservoir that could be targeted with extended-reach horizontal wells.

Design and Acquisition of the Second Generation 3-D Seismic Survey

This second generation seismic survey was obtained and analyzed after two of the new horizontal/deviated wells, NDP Wells #36 and #33, were drilled and initially completed. Thus the first two horizontal wells were designed based on the original 3-D survey, but results of the second survey were used to refine the original seismic interpretation as well as to identify new drilling targets.

The design of the 3-D seismic survey for the north end of the NDP incorporated receivers located on the shore and into selected areas of the playa lakes to record data from beneath mined areas. During the later part of March 2002, Dawson Geophysical and the Bureau of Land Management representatives met in the field to identify areas where receiver lines could be laid into the playa lakes. To acquire data under playa lakes and potash mines, the source and receiver points in the initial design were increased from 679 and 2491 to 1050 and 3886, respectfully. With this 60% increase in source and receiver points, the cost of the 3-D survey has increased by 53%; however, this design was expected to yield adequate resolution to provide useful data for targeting future wells. The final design is shown in **Fig**. **23**. It is believed that this was the first 3-D seismic survey designed to model the Delaware formation where surface and subsurface constraints, including voids created by underground potash mining, was attempted.

After obtaining permits for the 3-D seismic survey at the north end of the NDP, laying of the lines started on November 22, 2002 and was completed on December 8, 2002. The acquisition of data started December 8, 2002 and was completed December 16, 2002. A total of 9.5 mi^2 was shot, with 4371 receivers and 1191 source points.

The recording of the seismic data was suspended during the frac treatment on the NDP Well #33. An experiment was performed using the full 3-D receiver array to attempt to record micro-seismic events during the frac treatment. The 3-D Seismic array was cycled to be turned on to record for 1.5 minutes–off 5 minutes, for a total of 90 minutes. It was hoped that data could be extracted from the data set to aid in mapping fracture area and orientation. However, any induced fracture "noise" was hidden in the data and extraction of any useful information was not possible.

Interpretation of the New 3-D Data

Initial processing and interpretation of the data yielded some issues that had to be resolved 1) matching new amplitude maps to the original survey maps, 2) calibration of new data to existing well performance data, and 3) integration of existing data, new data and geological modeling to achieve a comprehensive geological model. The new seismic interpretation that was completed created some corrections in the original interpretation as to dip across Section 11 and new drilling targets.

The second generation seismic structure map (**Fig. 24**) indicated that there was only 16.7 m (55 ft) of west to east dip across Section 11. The first generation seismic structure map showed 38.1 m (125 ft) of west to east dip. This reinterpretation caused a problem with targeting the bottomhole location (BHL) of the horizontal wells drilled in Section 11. NDP Wells #33 and #36 were drilled using the dip exhibited by the first generation seismic survey and followed the "L" zone updip 22.9 m (75 ft) to 15.2 m (50 ft). The second generation seismic structure map indicated that these wells only need to go updip about 7.6 m (25 ft). Therefore, if the second generation structure map is correct, the bottomhole locations of Wells #33 and #36 are at the top of the "L" zone or in the bottom of the "K-2". This may explain why the water cut was higher than expected from the Well #33.

A possible explanation was offered to explain the varying structural interpretation.[32] When depth maps are made from seismic-derived velocities without the benefit of well control to constrain the depth estimates, the maps are usually correct in a relative sense, but rarely yield precise depths. In other words, structural highs are generally structural highs when drilled; structural lows are indeed structural lows, and positive and negative dips are usually correct indications of actual subsurface dips. Thus the depth picture is correct in a relative sense. However, the seismic estimate of the depth of a target can be in error by several tens of feet even though the relative subsurface geometry is correct. This depth error results because of the error bar associated with the estimate of seismic velocity, because the stacking velocity determined early in the seismic data-processing process was not optimal, or because anisotropy results in large differences between horizontal and vertical velocities. As an example, if the selected stacking velocity at image time of 1 second is 10,000 ft/sec, a 2-percent error in velocity estimation will result in a depth error of about 61 m (200 ft).

To improve the depth accuracy of seismic maps, well control should be incorporated into the depth conversion process so that wireline-measured depths of key formation tops can be tagged to seismic image times of those units. With a reasonable amount of well control as constraints, seismic depth maps can often be amazingly accurate, with depth predictions differing from actual depths by less than 3 m (10 ft) at depths of 2438 to 3658 m (8,000 to 12,000 ft).

With this background, the Nash Draw depth maps can now be discussed. The original depth maps that led to the drilling of NDP Wells #33 and #36 into Section 11 were made without any calibration wells in Section 11 to constrain the depth predictions. These first-generation maps were made using seismic-derived velocities across the total image space and control wells that existed only to the east of Section 11. The maps were affected by velocity error bars as the depth predictions moved farther away from each control well. These maps indicated that the depth of the Bone Spring, and units immediately above Bone Spring, decreased toward the west at a rate of about 100 ft per mile. The bottomhole depths of NDP Wells #33 and #36 were targeted based on this implied dip rate.

It is possible that the original depth maps are correct across Section 11 in a relative sense. The Bone Spring does become shallower to the west, but it is risky to assume that the dip is exactly 100 ft per mile. The error bars associated with the seismic velocities would allow this dip to vary by a few tens of feet over a distance of a mile.

The new seismic survey allowed the construction of new depth maps. The important difference in the depth mapping process with these new data, compared to the original depth mapping, was that there were then two control wells (NDP Wells #33 and #36) in Section 11. A Bone Spring depth was provided for each well, and these depth values were used to constrain the new seismic depth predictions (see **Fig. 25**). By definition, these new maps are more reliable depth maps than the first maps IF (and a most important "if") the Bone Spring depths provided for Wells #33 and #36 are correct. If these well depths are incorrect, then the seismic maps are incorrect, again by definition.

Dip Calibration

To calibrate the dip across Section 11, three models[8] were created using actual well data and seismic derived data. Case I used the actual formation tops from the NDP Wells #13 and #15 wells and two wells located approximately 4 km (2.5 miles) to the west. The indicated dip was 70 to 78 ft/mile. There was good agreement with the "L" zone top observed in Wells #33 and #36 and the projected Bone Spring top for each well. In this case the bottomhole locations for each well were at the top of the "L" zone.

Case II used the actual data from Wells #13 and #15 and the first generation seismic data. The indicated dip ranges from 81 ft/mile to 124 ft/mile. The observed formation tops in Wells #33 and #36 did not fit this dip model, indicating the dip was too steep. The bottomhole locations of both Wells #33 and #36 were in the middle of the "L" section.

Case III used the actual data from the NDP Wells #13 and #15 and the second generation seismic data. The indicated dip ranged from 43 ft/mile to 51 ft/mile. The observed formation tops in Wells #33 and #36 appeared to be above the projected formation tops, indicating the dip was too flat. The bottomhole location of Well #33 was above the "L" zone and the bottomhole location of Well #36 was just below the top of the "L" zone.

The true dip across Section 11 appears to be 50 ft/mile to 70 ft/mile with the bottomhole location of Wells #33 and #36 lying at the top of the "L" zone. Assuming the fracture stimulation treatments did not grow down into the "L" zone and only the "K" and "K-2" were contributing, a high water cut would be expected from these completions. This was confirmed by using the characterization model prepared on Well #15 using only the "K" and "K-2" zones. Initial production rates were calculated to be 122 BOPD and 511 BWPD, an 80% water cut. NDP Well #33 was producing with an 80% water cut, confirming the production may be coming primarily from the "K" and "K-2" zones.

These latter maps indicate the dips of the Bone Spring and the "K" and "L" reservoir targets are about 50 ft per mile across Section 11, not 100 ft per mile as estimated by the first-generation maps. These results suggest that the NDP Wells #33 and #36 should be drilled deeper into the "L" zone and recompleted.

Directional/Horizontal Wells

The reservoir characterization results from Phase I of the project identified several targets in the "K" and "L" zones beneath the potash mining areas in the north part of the NDP (**Fig. 26**). Limited surface access to these reserves was caused by the presence of playa lakes, flood planes, archeological sites, and caves (**Fig. 27**). As mentioned earlier, two directional/horizontal wells, NDP Wells #36 and #33, were drilled and initially completed based on the reservoir characterization results from Phase I. A third directional/horizontal well, NDP Well #34, was drilled after a second 3-D seismic survey was acquired and interpreted (**Fig. 28**). Results from the second seismic survey were used to recomplete zones in both of the first two wells.

Wells Plans

Because the cost of a directional/horizontal well is about two to three times the cost of a vertical well, careful attention was paid to details, equipment, tubulars, and hole conditions. The well plan for each well was an iterative process that considered factors including, hole size, casing program, mud program and equipment, directional drilling plan, drill pipe and collars, reservoir evaluation, cementing, completion, production, and regulatory issues.

Hole Sizes and Casing Programs

Directional/horizontal wells in the NDP were drilled with a 26 in. hole to 12.2 m (40 ft) with 20 in. casing, 17 ½ in. hole to 107 m (350 ft) with 13 3/8 in casing, 11 in. hole to 944.9 m (3100 ft) with 8 5/8 in casing, and 7 7/8 in. hole to total depth (TD) with 5½ in. casing. The 7 7/8 in. hole allowed the running of 5½ in. production casing and 2 7/8 in. tubing. A typical casing program is given in **Table 10**.

Drilling Rigs

The drilling rig used to drill NDP Well #36 was J.W. Drilling, Inc. Rig #3, Skytop Brewster N-75 with two D-379 Caterpillar engines with 575 hp each, a PZ-7 pump with a D-379 was the main mud pump and a EMSCO MM-700 pump was the standby pump, two 600 bbl steel pits, Bryant triple screen shaker and centrifuge, drill pipe 4 ½ in. 16.6 #/ft XH GD X-95. The drilling rig used for NDP Well #33 was Key Energy Services, Inc. Rig #37, draw works EMSCO D-2, 1100 HP, derrick 40.8 m (134 ft) L.C. Moore, 450,000#, Pump #1 PZ-9, 1,000 HP, 6 in. liners, Pump #2 PZ-8, 750 HP, 6 in. liners, mud system- 3 tanks, 900 bbl, 2 cone desander & 8 cone desilter, single screen shale shaker, drill pipe 4 ½ in.- 20#/ft grade "X", 4.5" XH. Drilling of NDP Well #34 used Adobe Drilling Rig #2, draw works Seacoast 750 HP, derrick 38.7 m (127 ft) L.C. Moore, 325,000#, Pump #1 EMSCO 800 triplex 6 in. liners, Pump #2 PZ-8 Caterpillar D-379, 6 ½ in. liners, three 600 bbl mud tanks, drill pipe 4 ½ in. 16.6 #/ft.

Mud Programs and Equipment

Details of the mud program are provided in **Table 11**. During the drilling of NDP Well #36, a four-panel motion shaker successfully removed most of the solids from the mud system. Solids content ranged from 0.8% to 2% which permitted the use of a semi-closed mud system. The mud system for NDP Well #33 used a closed mud system with two centrifuges, two cone desanders, and 8 cone desilters. A shale shaker with 175-250 mesh screens used with a centrifuge on NDP Well #34 kept solids to less than 1%. Mud properties for NDP Well #33 are shown in **Table 12**.

Directional Drilling Equipment

A typical bottomhole assembly is listed in **Table 13**. A 1.5^o bent sub proved to provide the required angle building capability. Some problems were encountered when hard laminations were being penetrated at a low angle. The bit would slide along the hard streak until sufficient weight could be applied to the bit. After penetration, the angle would build too quickly if the weight was not reduced and rotating started.

The heavy weight drillpipe provided ample weight to the bit. Problems with differential sticking in the turn reduced the ability to transfer weight around the turn. The addition of more collars or heavy weight drillpipe probably would not help this problem. Good weight transfer could only be accomplished by rotating and using lubricants.

Drill Bits

Standard bits were used to drill the vertical and horizontal sections. Due to the abrasive nature of the sands, the drill bits used in NDP Well #36 were worn out of gauge in a short period of time. A new bit design that had a diamond coating to protect the gauge was subsequently used and runs were much improved. The diamond enhancement for gauge protection aided in maintaining gauge hole. A listing of drill bits is given in **Table 14**.

Directional Drilling

Strata drilled the NDP Well #36, a directional/horizontal well, in the second quarter of 2001. The well extended 1125 m (3690 ft) at a bearing of 296^{o} northwest with a BHL in the SW/NE of Section 11 and the surface location in the NW/SW of Section 12. The plan was modified slightly to reflect the need to move updip approximately 15.2 to 18.3 m (50 to 60 ft). Three intervals at the toe of the well were initially targeted: Zone #1 at 2983-2989 m (9786-9805 ft), Zone #3 at 2885-2886 m (9464-9470 ft), and Zone #2 at 2781-2783 m (9123-9129 ft) (**Fig. 29**). The final well path for NDP Well #36 is shown in **Fig. 30**.

NDP Well #33 was drilled from a surface location located 3 m (10 ft) FSL and 53.3 m (175 ft) FWL of Section 12-T23S-R29E. The BHL is located 973 m (3192 ft) west and 810 m (2657 ft) north, displacement is 1266 m (4154 ft), measured depth is 2918 m (9573 ft), true vertical depth (TVD) is 2053 m (6736 ft). The wellbore encountered the target as shown in **Fig. 26**. The initial kickoff point was at 975.4 m (3200 ft) with the build angle averaging 3.5 deg./100 ft, to a total of 30 degrees at 1256 m (4122 ft). The 30 degree angle was maintained to 2114 m (6935 ft) where the angle was built at 12 degrees/100 ft until the wellbore was horizontal at 2344 m (7691 ft). The horizontal section was drilled at 92.5 degrees to follow the "L" zone updip to a total measured depth of 2918 m (9573 ft) (**Fig. 31**).

The interpretation of the second generation 3-D seismic yielded a drilling target in the NE/4 of Section 12 and the SE/4 of Section 1 (**Fig. 28**). NDP Well #34 was spudded on March 23, 2005 from the NDP Well #19 location to the SE/4 of Section 1. The well was designed to be a directional/horizontal well with the directional section intersecting the "L" zone approximately 427 m (1400 ft) northeast of the surface location at an azimuth of 51.98°. After intersecting the "L" zone, the wellbore was to continue horizontally to an approximate BHL at 122 m (400 ft) FSL and 122 m (400 ft) FEL of Section 1. The bottomhole location was projected to be 549 m (1800 ft) east and 970 m (3182 ft) north of the surface location, a total of 1114 m (3655 ft) from the surface location at an azimuth of 25.50°. The well reached total depth on April 28, 2005 at a measured depth (M.D.) of 2922 m (9585 ft), TVD 2089 m (6854 ft), displacement 1028 m (3372 ft) @ 30.16 ^{o}, BHL 516 m (1694 ft) E and 889 m (2916 ft) N. The final well path for NDP Well #34 is shown in **Fig. 32**.

Drilling Time

The initial plan called for NDP Well #36 to be drilled in 25 days. However, the NDP Well #36 took 47 days to drill due to hole problems, equipment problems and slow drilling rates (**Fig. 33**). For NDP Well #33, the anticipated drilling time without any delays was projected at 24 days. With time lost dealing with the differential sticking and slow drilling in the siltstone, the well took 36 days (**Fig. 34**). The estimated drilling time for NDP Well #34 was 22 days but the actual time was 39 days, 17 days extra, mainly due to differential sticking problems in the "K-2" zone at the bottom of the curve. Drag caused by differential sticking and multiple turns reduced the ability to transfer weight to the bit. Drilling time versus planned time for NDP Well #34 is shown in **Fig. 35**.

Rate of Penetration

NDP Well #33 was drilled with much fewer problems than Well #36, but the two main problems that were encountered were slow rates of penetration and differential sticking. Zones that have been produced in the field had low BHP that caused differential sticking problems at 1524 m (5000 ft) and 2225-2271 m (7300-7450 ft). The worst sticking was in the interval at 2225-2271 m (7300-7450 ft), which correlates to the "K-2" zone. The "K-2" is predominately water productive throughout the field, and a large volume of water has been produced from this zone. With the sands only about 0.3 m (1 ft) thick, horizontal drilling continuously encountered shales and siltstones. The shales and siltstones are "gummy" and impede drilling. Rate of penetration (ROP) averages about 30-60 ft/hour in clean sands but was >10 ft/hour in the shales/siltstone (**Fig. 36**). Drag increased at the turn increased due to the differential sticking but was decreased at TD by the addition of lubribeads (**Fig. 37**).

The well plan for NDP Well #33 was modified based on several problems encountered while drilling Well #36. Sufficient weight was not available at the bit to drill Well #36 effectively, so heavy weight drillpipe was used below the drill collars. However, differential sticking in the turn continued to keep weight off the bit, and if we went any farther than 4000-5000' casing would need to be set through the turn to shut off the "K-2" zone. During the drilling of NDP Well #36, a keyseat was created due to a change in direction at the first kick off point at 960 m (3150 ft) (**Fig. 38**). On Well #33, a deviation survey was run at 762 m (2500 ft) (**Fig. 39**) and the bottom part of the intermediate hole was directionally drilled with steering tools which kept the hole straighter than on Well #36.

The drilling of NDP Well #34 experienced the same problems as the Wells #33 and #36:

1. Slight keyseat at 991 m (3250 ft) as shown in **Fig. 40**.
2. Water flow at 1372 m (4500 ft).
3. Differential sticking at 2057 m (6750 ft).
4. Difficulty penetrating a hard lime streak at 2996 m (6830ft).
5. Difficulty transferring weight to the bit.
6. Multiple MWD failures.

Cementing

Details on cementing the surface, intermediate, and long string pipe in NDP Wells #36 and #33 are outlined in **Table 15**. Information on the cementing of NDP Well #34 is provided in **Table 16**. Cement bond logs indicated fair to excellent bond throughout the vertical section of all three wells, and a CBL was run in the horizontal section on Well #34 that showed fair to good bond.

Completion

Three completion strategies were investigated for the directional/horizontal wells at the NDP: Option 1 was an uncemented ported liner with one large high-rate frac treatment, Option 2 was an openhole completion with one large high-rate frac with diversion, and Option 3 provided for cemented casing with selective perforating and stimulation. Options 1 and 2 were simple one-stage completions, but there was no assurance that all zones would be treated. With Option 1 there was an unknown about what would happen in the annulus, and with Option 2 the stability of a long open hole was a concern. Option 3 involved a more complicated completion, and there was concern regarding the availability of equipment to perform multiple completions and/or diversion between zones. However, Option 3 was chosen because it insured that each zone would be stimulated. Option 3 also was felt to have procedures that could better deal with varied treating pressures and rock properties.

Completion of NDP Well #36

The completion of NDP Well #36 started in October 2001 with the completion of Zone #1 at 2983-2989 m (9786-9805 ft) in the toe of the well. The procedures used in the initial completion are displayed in **Table 17**. The high treating pressure that was initially seen (see **Fig. 41**) in the frac treatment was attributed to tortuosity. **Fig. 42** shows the typical treating pressures encountered in a vertical well frac treatment. The toe frac was expected to treat at approximately 12,410 kPa (1800 psi). The initial treating pressure was 25,579 kPa (4000 psi) at 5-26 L/s (2-10 barrels per minute) (BPM). Two shut-ins were observed with initial shut-in pressure (ISIP) of 6205 kPa (900 psi). After starting the treatment and establishing a rate of 66 L/s (25 BPM), the treating pressure was approximately 26,200 kPa (3800 psi). This was approximately 13,790 kPa (2000 psi) above the anticipated pressure. At 125 minutes into the treatment, the 0.48 kg/L (4 ppg) sand concentration was on the formation and a momentary 3447 kPa (500 psi) increase in treating pressure was observed. By the end of the treatment after pumping 100,698 kg (222,000 lbs) of 16/30 sand, the treating pressure decreased to 16,547 kPa (2400 psi) and the ISIP was 8274 kPa (1200 psi).

The completion procedures used for “L” Zones #2 and #3 are listed in **Table 18**. The first Mohave frac treatment of Zone #3 at 2885-2886 m (9464-9470 ft) was anticipated to treat at 41,369 kPa (6000 psi) at 37 L/s (14 BPM), but the initial treating pressure was 56,192 kPa (8150 psi) at 37 L/s (14 BPM), a 13,790 kPa (2000 psi) increase over the anticipated pressure (**Fig. 43**). Unlike the toe frac, the ending treating pressure did not decline and was 55,158 kPa (8000 psi) at 37 L/s (14 BPM) with an ISIP of 6860 kPa (850 psi).

The second Mohave frac treatment of Zone #2 at 2781-2783 m (9123-9129 ft) was anticipated to treat at 41,369 kPa (6000 psi) at 37 L/s (14 BPM). The initial treating pressure was 55,848 kPa (8100 psi) at 36 L/s (13.6 BPM), again a 13,790 kPa (2000 psi) increase over the anticipated pressure (**Fig. 44**). Unlike the first Mohave frac, the ending treating pressure declined slightly to 51,021 kPa (7400 psi) at 38 L/s (14.4 BPM) with an ISIP of 8205 kPa (900 psi).

The completion procedures were followed as planned with a few modifications due to unforeseen problems. The main problems were:

1. The rubber cups on the Mohave frac tool were delicate and became cut when the tool was being run in the hole and when the tool was moved to the second interval. This necessitated two extra trips with the coiled tubing to replace damaged cups.
2. The treating pressure on the toe interval was approximately 13,790 kPa (2000 psi) higher than anticipated. This was attributable to tortuosity and was partially relieved by pumping large volumes of sand.

3. The treating pressure on the two Mohave fracs were approximately 13,790 kPa (2000 psi) higher than anticipated. This was attributable to tortuosity and was only partially relieved by pumping sand.
4. High initial production rates made testing and production difficult.

The ISIP's were similar to vertical well shut-ins, but treating pressures were 13,790 kPa (2000 psi) above normal vertical well treating pressures. With the ISIPs of 6205 kPa (900 psi), the frac gradient was estimated to be 12.9 kPa/m (0.57 psi/ft) with the resulting closure pressure of 26,614 kPa (3860 psi). This correlates closely to frac gradients and closure pressures observed in vertical wells in the field. The additional treating pressure was attributed to high friction pressure due to a tortuous path of the induced fracture from a horizontal point to large vertical fracture, multiple narrow induced fractures, and near wellbore fracture geometry that is in a different plane than perpendicular to the least principle stress. Whichever mechanism or combination of mechanisms contributed to the higher treating pressures, it also caused narrow fracture widths as evidenced by the pressure increases when sand concentrations were stepped up. Maximum sand concentrations were only 0.36-0.48 kg/L (3-4 ppg) on this well, with indications that higher concentrations could not be tolerated. On the vertical wells in the field, maximum sand concentrations are routinely run at 0.71 kg/L (6 ppg).

A sample of sand recovered after the frac treatments was analyzed to determine the source of fines observed in the sample. The sample was viewed under a microscope and the fines were determined to be fragments of crushed frac sand. The sand used in the treatments was 16/30 and 20/40 Jordan sand. The sieve analysis of the recovered sample indicated that 100% would pass through a 20 mesh screen, 94% would pass through a 30 mesh screen, 27% would pass through a 40 mesh screen and 9.2% would pass through a 50 mesh screen. The sand retained on the 50 mesh screen was 50% crushed, and the sand that passed the 50 mesh screen was 90% crushed. No large grains, in the range of 16/20, were observed in the sample. Either the large grains were caught in the induced fracture system or the recovered fines were the remains of the larger grains.

After the wellbore pressure was drawn down, the crushed frac sand that was recovered indicated high closure pressures near the wellbore. Crushing of the proppant may have been aided by cyclical loading due to high flow rates and pressure drawdowns coupled with shut-in periods and resulting wellbore pressure buildup.

A bottomhole pressure buildup test in Well #36 (**Fig. 45**) was performed and analyzed. The test indicated a low permeability zone with little or no stimulation. The conclusion was that the sand proppant crushed in the near wellbore region and the zone was not effectively stimulated.

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Restimulation of NDP Well #36

In April 2002 a restimulation treatment for NDP Well #36 was designed to clear the damaged proppant in the near wellbore region, create additional frac height, and place a high strength proppant to reestablish communication with the existing treatments. The treatment design consisted of 223,339 L (59,000 gal) of 4.2 g/L (35 lbs/1000 gallons) crosslinked fluid carrying 68,039 kg (150,000 lbs) of C-Lite ceramic proppant at 185-199 L/s (70-75 BPM). Initial pressures built up to 29,537 kPa (4284 psi) before the crushed proppant was displaced, and the treatment was pumped at 18,271 kPa (2650 psi).[7] There was still 4826 kPa (700 psi) of excess pressure attributable to tortuosity/closure pressure. The lower treating pressures (**Fig. 46**) indicated that the refrac entered the existing induced fracture and the effects of the near-wellbore tortuosity/closure pressure were reduced on the order of 8963 kPa (1300 psi) by the erosion effects of pumping large quantities of proppant. After the load was recovered and the wellbore cleaned out with coiled tubing and nitrogen, fluid entry appeared to be adequate.

During the workover, a potentially productive zone in the deviated section of NDP Well #36 was identified from 1930-1936 m (6332-6352 ft) (M.D.). This second sand in the “H” series is designated the “H-2” zone. This zone had porosity as high as 18.5%, core air permeability as high as 49 md, good oil saturations, and good log response. The “H-2” was perforated from 1930-1935 m (6333-6349 ft) with 14 perforations. Stimulation included an acid breakdown and cleanup treatment with 5678 L (1500 gallons) of 7½% HCL NEFE acid with ballsealers for diversion. After load recovery and satisfactory testing, the interval was fracture stimulated with 30,283 L (8,000 gallons) of 3.6 g/L (30 lb/1000) gallons crosslinked gelled water carrying 5443 kg (12,000 lbs) of 16-30 CRC sand. Treating pressures were within the normal range and the ISIP was 6219 kPa (902 psi).

NDP Well #36 Production

As shown in **Fig. 47**, initial production from NDP Well #36 declined rapidly. Because of the production of water slugs and high line pressure, there were problems keeping the well flowing, so a gas lift system was installed to handle the increased fluid volume and stabilize production. Nine gas lift valves were installed in the tubing string and an 800 MCFGD compressor was installed to supply power gas.

Prior to the April 2002 workover the toe zone produced 16,108 BO, 46,513 MCFG and 34,834 BW. During this phase different production strategies were tried, including natural flow, rod pumping and gas lift. Gas lift proved to be the most reliable and had the capacity to move the large volumes of liquids.

In April 2002, a bridge plug was set to shut off the toe zone in NDP Well #36, and the “H-2” zone was cleaned up and the well was put on production. The average production for May 2002 was 385 BOPD, 587 MCFGD and 140 BWPD. As of September 30, 2002 the “H-2” zone had cumulative production of 41,464 BO, 78 MMCFG, and 9111 BW and production rates were 190 BOPD, 400 MCFGD and 27 BWPD. The “H-2” zone continued to flow, and, as of August 31, 2003 the zone had cumulative production of 94,036 BO, 258 MMCFG, and 43,693 BW and production rates were 70 BOPD, 451 MCFGD and 25 BWPD. Cumulative production through January 2004 was 103,196 BO, 330 MMCFG and 45,950 BW. Production from the “H-2” from April 2002 through May 2004 was 98,846 BO, 353,412 MCFG and 24,169 BW.

In June 2004 the composite bridge plug was drilled out and the toe zone and “H” zone were commingled. Production prior to pulling the bridge plug was 47 BOPD, 406 MCFGD and 15 BWPD. After the bridge plug was removed, the production stabilized at 90 BOPD, 400 MCFGD and 180 BWPD.

A reservoir simulation was performed to estimate the drainage area of Well #36. A 24 x 24 grid was populated with porosity, permeability, structure, and porosity derived from actual well data where available and a simple nearest neighbor geostatistical calculation for interwell data. Once the basic data was entered and the simulation debugged, the cell dimensions were varied from 67.1 x 67.1 m (220 ft x 220 ft) to 24.4 x 24.4 m (80 ft x 80 ft) to match the actual production from Well #36. A good match was found when the cell dimensions were 30.5 m 30.5 m (100 ft x 100 ft). The actual production versus simulator production is shown in **Fig. 48**. This analysis indicates the reservoir area attributable to Well #36 covers approximately 130 acres. The reservoir simulation model proved to be a good match to the actual oil production. The actual produced gas volume appears higher than predicted, but after comparing the field volumes to the actual purchased volumes, the field volumes were 30% to 40% too high. Purchased volumes plus fuel usage were much closer to the predicted gas volumes.

Cumulative production from the Nash Draw Well #36 through September 1, 2005 was 145,185 BO, 585,935 MCFG and 127,739 BW (**Table 19**). In the last part of March 2005, a larger compressor was installed in Well #36. As seen in the daily production plot (**Fig. 49**), production stabilized at 60 BOPD, 387 MCFG and 123 BWPD, the GOR stabilized at 6.5 MCFG/BO.

Plans are being finalized to complete additional zones in the heel section in NDP Well #36. After the "H-2" and toe zones are produced, two zones in the heel section in NDP Well #36 will be completed: Zone #4 at 2438-2439 m (8000-8002 ft) and Zone #5 at 2286-2287 m (7500-7502 ft). A composite bridge plug will be set and each zone will be perforated with 6 shots per 0.3 m (ft). A string of 3½" frac tubing will be run and a packer set at about 1963 m (6440 ft). Plans are to acidize the perforations with 15,142 L (4000 gallons) 7½% NEFE acid with 36 biodegradable ballsealers. The planned hydraulic fracturing treatment will be composed of 264,979 L (70,000 gallons) micellar fluid carrying 45,359 kg (100,000 lbs) of 16/30 ceramic proppant. After testing, the composite bridge plug will be drilled out and all zones will be commingled.

NDP Well #33 Completion

The toe zone in NDP #33 was completed in December 2002 and "H" zone was completed soon afterward in February 2003. The initial completion in NDP Well #33 was in the toe of the well through 9.8 m (32 ft) of open hole. After setting and cementing the 5.5 in. casing, the shoe joint and 9.8 m (32 ft) of formation were drilled with a mud motor and a 4.75 in. bit. The openhole section was from 2918 m (9573 ft) to 2928 m (9605 ft). The general approach is summarized in **Table 20**.

To aid in formation breakdown and attempt to control fracture initiation, a hydraulic jetting tool was run into the open hole and a groove was cut into the formation approximately 3 m (10 ft) from the end of the well. Jetting was accomplished with a four jet head, rotated at 6 rpm while pumping slick water at 13 L/s (5 BPM) at 15,858 kPa (2300 psi) for 45 minutes (**Fig. 50**). The breakdown pressure on Well #33 was 18,616 kPa (2700 psi) at 58 L/s (22 BPM) compared to 28,220 kPa (4093 psi) at 5 L/s (2 BPM) on Well #36. It was apparent that the jetting aided in the initial breakdown and aided in fracture initiation. The toe zone breakdown and cleanup is shown in **Fig. 51**.

The fracture stimulation treatment was designed to create 145 m (475 ft) of fracture half-length with 73.5 m (241 ft) of fracture height by using 4.7 kg/m^2 (0.96 lb/ft^2) proppant concentration to yield about 8,000 md-ft flow capacity. The design resulted in pumping 264,979 L (70,000 gallons) of 4.2 g/L (35 lb/1000 gal) complexed borate gelled 2% KCL water carrying 90,718 kg (200,000 lbs) of C-Lite (ceramic proppant) at 80 L/s (30 BPM).

The initial breakdown was lower than experienced on Well #36, but fracture propagation was hampered by the maximum pressure limitation of 34,474 kPa (5000 psi). The rate decreased and pressure increased throughout the pad. The fracture friction-tortuosity pressure increased to the point that the job gelled out and was shut down. To enable the maximum treating pressure to increase, a wellhead isolation tool was used to isolate the 34,474 kPa (5000 psi) working pressure (W.P.) wellhead and allow the maximum treating pressure to increase to 43,437 kPa (6300 psi) (**Fig. 52**). After pressuring up to 42,747 kPa (6200 psi) to initiate fracture propagation, the treatment was pumped at 80 L/s (30 BPM) at 22,063 kPa (3200 psi) (**Fig. 53**). Just as the displacement was completed, the treatment sanded-out without leaving any excess proppant in the casing. After being shut-in for three hours the well was opened on a 1/8 in. choke and allowed to flow back the load.

The "H" zone and the toe zone were commingled with a nine-valve gas lift system designed to lift 1500 barrels of fluid per day. Some initial problems were experienced due to compressor suction pressure, high line pressure, and one leaking valve. Most of these problems were resolved quickly, and lift efficiency was maximized by monitoring the bottomhole producing pressure.

To enhance production, completion of three intervals in the heel area was started in December 2003 and completed in January 2004. A composite bridge plug was set at 2804 m (9200 ft) M.D. to isolate the toe zone. The additional intervals were at a M.D. of 2722-2722 m (8929-31 ft), 2468-2467 m (8098-8100 ft) and 2324-2324 m (7624-26 ft). Each zone was perforated using coiled tubing conveyed guns, with six shots per 30.48 cm (foot) for each 0.61-m (2-ft) interval, then acidized and fracture stimulated.

A straddle packer assembly was used to acidize each interval separately. The packer assembly worked successfully on the first interval, but the second and third interval could not be acidized due to tool failures, and the straddle treatments were aborted. A string of 3.5 in. P-105 tubing was run with a fullbore packer, and the packer was set at 2072 m (6799 ft). The three heel zones were acidized with 30,283 L (8,000 gallons) 7½% NEFE acid and 30 biodegradable ball sealers every 9,539 l (60 barrels). The treating rate was 21-32 L/s (8-12 BPM), and treating pressure was 26,200 kPa (3800 psi) with good ball action. The instant shut down pressure was 5792 kPa (840 psi) and the 15 minute shut-in pressure was 3723 kPa (540 psi). Treating pressures and shut down pressures indicated normal treating pressures and little if any tortuosity problems.

After load recovery the heel zones were fracture stimulated with 20,185 kg (44,500 lbs) of 16-30 sand carried by 75,708 L (20,000 gallons) spacer and prepad and 151,416 L (40,000 gallons) of micellar fluid. The treatment was terminated early due to a sudden increase in the treating pressure and a drop in rate. As shown in **Fig. 54**, at 3500 seconds the pressure increased to 51,711 kPa (7500 psi) and the rate decreased to 64 L/s (24 BPM). This indicated a possible “sandout” so sand was stopped and the treatment flushed. This represented approximately one-third of the planned proppant of 65,317 kg (144,000 lb). The well was cleaned out with coiled tubing and returned to production to test the heel zone.

In May 2004 a coiled tubing unit was rigged up on the well and a 1.76 in. bit and motor assembly was run in the hole to drill a hole through the composite bridge plug. The plug was tagged at 2799 m (9183 ft) and drilled out to 2801 m (9189 ft). The hole was circulated clean and the well returned to production by gas lift.

Nash Draw #33 Deepening

The analysis of the second seismic survey indicated that the toe zone lies at the top of the “L” zone and the stimulation treatment did not extend down into the “L” zone. This may have resulted in a “K” and “K-2” zone completion with characteristically high water cuts and low oil cuts. The target zone was based on the Bone Spring top determined from the initial 3-D seismic survey. A rise of 21 m (70 ft) was projected over the length of the horizontal section. To correct this situation a deepening operation was designed to extend the openhole section 112 m (367 ft) while dropping the TVD 15 m (50 ft) deeper (**Figs. 55 and 56**). This should place the BHL at the bottom of the “L” zone porosity interval and allow fracture stimulation of the “L” zone. Proppant was observed throughout the deepening which indicated the actual frac length was close to the initial predicted frac geometry and the fracture orientation was longitudinal with the wellbore. Therefore additional deepening was not necessary.

NDP Well #33 Production

When Well #33 was drilled, the toe zone at 2918-2928 m (9573-9605 ft) was completed in December 2002. The “H” Zone at 2000-2037 m (6562–6682 ft) was completed shortly thereafter in February 2003. The “H” zone was tested in two intervals: 2039-2042 m (6691–99 ft) and 2000-2037 m (6562–6682 ft). The two zones were tested separately to determine if the lower interval was water-productive. The Advanced Log Analysis Program showed the interval 2039-2042 m (6691–99 ft) was water-productive and the interval 2000-2037 m (6562–6682 ft) was oil-productive. Testing the lower zone was necessary because, while this zone correlates to zones in other wells that are productive, it was lower structurally.

Testing showed the lower zone was water-productive with a 10% oil cut and the upper zone was oil-productive. The upper zone was then isolated and fracture stimulated with 151,416 L (40,000 gallons) of 3.6 g/L (30 lb/1000 gal) crosslinked KCL water carrying 27,669 kg (61,000 lb) of 20–40 sand. The average treating rate was 53 L/s (20 BPM) and the average treating pressure was 26,200 kPa (3800 psi). The treating pressure indicates there was some tortuosity effect in the deviated hole similar to that observed in treatments in the horizontal hole. Production from the toe zone and “H” zone in Well #33 are displayed in the first part of **Fig. 57**.

In January 2004 three heel zones at 2722-2722 m (8929-31 ft), 2468-2467 m (8098-8100 ft) and 2324-2324 m (7624-26 ft) were completed, and a composite bridge plug was set to isolate the toe zone. In May 2004 the composite bridge plug was drilled out and all zones were commingled. Production prior to drilling the bridge plug was 99 BOPD, 133 BWPD and 390 MCFGD.

Production in July 2004 after drilling the bridge plug was 94 BOPD, 188 BWPD and 351 MCFG (**Fig. 57**). Due to increased water production, the partial depletion of the heel zones and higher producing BHP, it appeared that the heel zone in NDP Well #33 was not contributing any substantial amounts to the production. Based on this, the planned deepenings of NDP Wells #36 and #34 were canceled.

As seen in the daily production plot of Well #33 (**Fig. 57**), gas volume and total fluid volumes were increasing. In late November 2004 the compressor powering the gas lift system was replaced with a slightly larger unit. Production prior to exchanging compressors was 83 BOPD, 194 BWPD and 184 MCFGD. Production after exchanging compressors was 107 BOPD, 247 BWPD and 563 MCFG. As seen in the daily production plot (**Fig. 57**), the gas volume stabilized at 550 MCFGD and the oil volume stabilized at 105 BOPD.

Cumulative production from the Nash Draw #33 through September 1, 2005 was 98,531 BO, 318,587 MCFG and 224,601 BW. Daily production was 98 BOPD, 550 MCFGD and 230 BWPD (**Table 19**).

NDP Well #34 Completion

To complete NDP Well #34, the well was extended 13.7 m (45 ft) from 2922 m (9585 ft) to 2935 m (9630 ft) with a 12.1 cm (4 ¾ in.) diameter open hole. To aid in breakdown, penetrate multiple laminations, and help initiate a hydraulic fracture, a 6.4 cm x 305 cm (2 ½ in. x 10 ft) cylinder of rocket fuel was ignited at the end of the openhole section. This created a short pulse of about 137,895 kPa (about 20,000 psi) pressure that created multiple fractures adjacent to the wellbore.

The toe zone was acidized with 18,927 L (5,000 gallons) of 7½% NEFE acid. The treatment was performed down open-ended tubing with a pressure monitor on the annulus. The treating pressures are summarized in the **Table 21.**

The breakdown pressure, and the difference between the annulus treating pressure and the ISIP pressure of 5792 kPa (840 psi), indicates the "tortuosity" is much less than the completions on Wells #33 and #36.

The toe zone was designed to be fracture stimulated with 234,696 L (62,000 gal) of ClearFrac J533-40 carrying 88,450 kg (195,000 lb) of C-Lite proppant. The pad was pumped at 19,815 kPa (2874 psi) and 132 L/s (50 BPM), approximately 13,790 kPa (2000 psi) lower than the Well #33 and Well #36 toe frac treatments. With 0.48 kg/L (4 ppg) of proppant on the formation, the treatment "screened-out" at a maximum pressure of 37,232 kPa (5400 psi). Approximately 18,144 kg (40,000 lbs) of proppant was placed in the formation (20.5 % of proppant total).

During the cleanout of the proppant in the casing, a black material was recovered from 2499 m (8200 ft) to TD. This material was very viscous and was clinging to the proppant. Samples were collected and sent to Schlumberger's Houston lab for analysis. SEM-EDS analysis indicated the main components in the sample were sodium (43.6 wt %), calcium (14.4 wt. %), aluminum (8.8 wt. %), iron (7 wt %) and chloride (19.9 wt. %). The high concentration of calcium, aluminum and iron are not consistent with the frac fluid.

Sources of contamination such as the water, chemicals, and proppant were checked and no definitive source of contamination was found. A review of pretreatment fluid samples showed no adverse reactions and showed proper viscosity development. To date the source of contamination has not been found.

Because of the sandout that occurred in the initial completion of Well #34, plans are being made to refrac this well with 45,360 kg (100,000 lb) 16/30 sand, 45,360 kg (100,000 lb) 16/30 ceramic proppant, and 18,144 kg (40,000 lb) of resin-coated ceramic proppant. After production from the toe zone is evaluated, completion of two additional zones in the heel will be considered.

NDP Well #34 Production

NDP Well #34 was completed and put on production in June 2005. Initial production rates of Well #34 were high at 250 BOPD with 300 MCFG, and after 60 days production had stabilized at 66 BOPD, 159 MCFG and 111 BWPD (**Fig. 58**). Cumulative production for NDP Well #34 through September 1, 2005 was 7,221 BO, 11,193 MCFG and 11,962 BW (**Table 19**).

Total Production and Reserves from DOE Project Wells

The production database for the NDP project was updated through August 2005. These data were added to the history of each well to update the decline curves and to project ultimate recoveries as well as to assess the effects of interference and production strategies. Production and estimated reserves from the nine wells that were part of the DOE Class III project (NDP Wells #12, 23, 24, 25, 29, 33, 34, 36 and 38) are given in **Table 19**.

Increased Production and Reserves from Workovers on Vertical Wells

To develop additional reserves from existing vertical wells at low costs, the advanced log analysis techniques developed Phase I were used to evaluate zones behind pipe in uphole zones of the Brushy Canyon interval. From 1999 to 2003, fourteen recompletions were done in thirteen NDP wells. Four wells (NDP Wells #13, #15, #19, and #24) were recompleted in 1999 which resulted in the addition of reserves of 73,842 BO and 36,921 MCFG. This allowed the development of economical reserves during a period of low crude oil prices and encouraged the continued use of the technique. An additional four wells (NDP Wells #5, #6, #11, and #23) were recompleted during 2000, which resulted in 123,462 BO and 453,424 MCFG reserves being added at a development cost of $1.57 per barrel of oil equivalent (BOE). Two wells, NDP Wells #29 and #38, were recompleted in 2001 which added 7,000 BO and 18 million cubic feet of gas (MMCFG) to the reserves at a cost of $9.70 per BOE. During 2002-2003, NDP Wells #1, #12, #15, and #20 were recompleted in uphole zones which added 128,000 BO and 150 MMCFG to the reserves at a cost of $1.65 per BOE. Total reserves added from the workover of vertical wells at the NDP were 332,304 barrels of oil (BO) and 640,363 MCFG (thousand cubic feet of gas). Overall, the weighted average development cost of workovers at the NDP was $1.87 per BOE.

Production and Reserves Added from Directional/Horizontal Wells

Well #36, the first directional/horizontal well in the NDP, was drilled in 2001 at a cost of $3,143,441. The second directional/horizontal well, NDP Well #33, was drilled and completed in 2002 at a cost of $2,502,942. The third directional/horizontal well, NDP Well #34, was drilled and completed in 2005 at a cost of $2,985,518. Cumulative production from NDP Well #36 through August 31, 2005 was 142,111 BO, 515,776 MCFG and 100,929 BW (**Table 19**). Cumulative production from NDP Well #33 through August 31, 2005 was 92,928 BO, 300,816 MCFG and 209,404 BW. Although NDP Well #34 had only been on production for a short time to that date, cumulative production was 6,370 BO, 12,071 MCFG and 11,962 BW. Total estimated reserves are 380,355 BO and 2,255,814 MCFG for Well #36, 209,988 BO and 628,585 MCFG for Well #33, and 287,792 BO and 985,402 MCFG for Well #34. Total estimated reserves from all three of the horizontal wells are 878,135 BO and 3.87 BCFG. The ratio of net revenue to cost is approximately 3.5 to 1 for Well #36 and 2.3 to 1 for Well #33 at an oil price of $30 per barrel that existed when the wells were drilled. The project economics that are reported below reflect more recent pricing.

As of September 1, 2005, the nine wells that were part of the DOE Class III project (NDP Wells #12, 23, 24, 25, 29, 33, 34, 36 and 38) have produced 526,947 BO, 3.04 BCFG and 2,132,427 BW (**Fig. 59**). Reserves associated with this project are summarized in **Table 1**. Remaining proved reserves are 421,586 BO and 2.05 BCFG. Proved undeveloped reserves are 353,026 BO and 1.64 BCFG. Total reserves from the DOE project wells are 1.3 million BO and 6.73 BCFG.

Project Economics

A detailed reserve study was performed with an effective date of July 1, 2005. The results of that study are shown in the **Table 19**. As discussed above, ultimate recovery from the nine project wells is projected to be 1.3 million barrels of oil and 6.73 BCF natural gas. Using a 6 to 1 ratio gas to oil, this equates to 2.35 million BOE. Using the project economic summary in **Table 22** the following parameters are presented:

1. Tangible costs, intangible costs and equipment costs total $14,331,359, divided by the 2,353,379 BOE, indicates a development cost of $6.09 per BOE.

2. The estimated total lease operating cost is $12,586,840, divided by the 2,353,379 BOE, indicates a lifting cost of $5.35 per BOE.

3. Using the development cost of $14,331,359 and the Net Revenue of $29,024,263 indicates a before tax return on investment of 3.03 to 1.

The economic summary in **Table 22** assumed an oil price of $40 per barrel and a gas price of $7 per MCFG. A similar study was also done with $30/barrel oil and $5/MCFG which also showed favorable economics. These results show that this project has acceptable economics and similar projects can be economically developed as long as oil and gas prices remain over $30 per BOE.

Extension of the Technology to Other Applications

Strata has applied the characterization and 3-D seismic technology developed from the Nash Draw project to two other fields in Eddy Co. NM and a new prospect west of the Nash Draw Unit. Another application is being modeled for a Bone Spring prospect in Lea County.

One of the fields is the Forty-Niner Ridge Field which is located approximately 4.8 km (three miles) east of the NDP. Preliminary planning includes the drilling of seven (7) wells which are projected to produce 1,050,000 BO and 5 BCFG. In February-March 2005 two wells were drilled in the Forty Niner Ridge Field based on seismic interpretations using the Nash Draw parameters. Wells #4 and #6 were drilled based on the “L” zone seismic anomaly similar to the anomalies observed at the NDP.

Gross thickness of the “L” interval in Well #4 was 38 m (126 ft) and net sand thickness was 17 m (55 ft). While the gross thickness of the “L” interval was a little thicker and net sand thickness was similar to wells in the NDP, the porosity of the “L” interval in Well #4 was only 8-10% versus 10-16% at the NDP. The “L” zone was completed, but the majority of the production is coming from the adjacent Lower Brushy Canyon “J” and “K-2” zones. In July 2005, the “F-3” and “D” zones were completed. Through the end of September 2005, Well #4 had produced 8189 BO, 12,897 MCFG and 23,878 BW. The production rate at that time was 70 BOPD, 80 MCFGD and 200 BWPD. Additional zones in the “H” and “I” intervals will be completed in the future.

Well #6 encountered an “L” interval 41 m (134 ft) thick with 15 m (50 feet) of net sand. While a little thicker gross interval and similar sand thickness as the NDP, the porosity was only 6-12% versus 10-16% at the NDP. The “L” zone was completed, but the majority of the production is coming from the Lower Brushy Canyon “K” and “K-2” zones. Through September 2005, Well #6 had produced 3261 BO, 6131 MCFG and 14,222 BW, and the production rate was 15 BOPD, 35 MCFGD and 40 BWPD. Shallow zones that show potential will be tested later.

While the “L” sand intervals in the Forty Niner Ridge wells were thick as predicted from the seismic anomalies, it was disappointing that the porosities were below the 10% productive limit. These results will be used to calibrate the seismic in this area, and additional potential will be evaluated based on the results from these two wells as well as from pending deep exploratory wells.

Summary and Future Implications

The primary objective of the NDP project was to demonstrate that developmental drilling based on enhanced reservoir management practices could significantly improve oil recovery at the NDP. To achieve this objective we had to better understand the complexity and recovery mechanisms of the Delaware formation. The information gathered and the technology which has been developed, demonstrated, and transferred to both industry and academia, is applicable not only to the Delaware formation but other complex reservoirs, both conventional and unconventional. As a result of the success of the project, billions of barrels of oil equivalent

(BOE) may now be recoverable in southeastern New Mexico, west Texas, and throughout the Nation.

Strata assembled a highly qualified multidisciplinary technical team. This team began the project with the goal of increasing what appeared to be an unusually low primary recovery (i.e. less than 10%) of the original oil in place. Information was obtained from a full core analysis, hundreds of sidewall cores, openhole well logs, PVT data, pressure buildup tests, well interference tests, analysis of historical production data, and 3-D seismic surveys. This information provided a better understanding of the vertical and horizontal complexity, heterogeneity and compartmentalization of the primary producing interval throughout the identified field area.

As additional wells were drilled, the subsurface mapping evolved from a one sand lobe body, to multiple lobes, and finally to a series of channels. It became increasingly clear that the geologic model had not been correctly identified. The first 3-D seismic program demonstrated that the NDP was producing from a reservoir located in the fan portion of a deep basin turbidite flow and not from one, or a series of sand lobes or channels, as initially believed. Early in the Project it was unclear if 3-D seismic technology had evolved to a point where it would be a useful tool in this particular geologic setting. Because of the quality control and design of the 3-D seismic program, resolution of excellent quality (i.e. 4.6 to 7.6 m or 15 to 25 ft) was achieved. Additional drilling confirmed the seismically identified areas of good quality reservoir, and production pressure analysis confirmed the areas which appeared to be compartmentalized based on the seismic analysis. While the reservoir was horizontally complex, and in some areas compartmentalized, this new understanding of the geology indicated that the field could possibly extend under areas of limited surface access (i.e. playa lakes and areas of subsurface potash mining.)

Analysis of the second 3-D seismic survey indicated the presence of excellent quality reservoir in the area underneath the potash mines and playa lakes. The drilling and completion of the first horizontal well (NDP Well #36) confirmed the accuracy of the 3-D seismic surveys and almost doubled the field area and the estimated recoverable oil and gas reserves. To date, an additional two horizontal wells (NDP Wells #33 and #34) have been successfully drilled and completed. An additional two to three directional/horizontal wells at the NDP are planned. Early in 2006, NDP Well # 48 is scheduled to be drilled in the north half of Section 11. Later, drilling plans include Well #46 in the west half of Section 14 and Well #49 into the middle of Section 7.

Prior to the initiation of the NDP DOE Project, the proved producing recovery was estimated to be 1.9 MMBO and 5.23 BCFG, or 2.75 million BOE. Today we estimate the field will ultimately recover on the order of 5.3 million BOE, an increase of almost 200%. The 3-D seismic and horizontal drilling techniques have been the major contributors to this increase. However, new and innovative technologies such as the advanced log analysis program have also contributed by identifying previously by-passed pay intervals. Implementation of this program at the NDP has added reserves of 332,304 BO and 640,363 MCFG at an overall development cost of $1.87 per BOE. As a result, the log analysis program is now being utilized throughout the Permian Basin.

Upon completion of the DOE project, Strata and the other Nash Draw owners will have invested approximately $12.1 million dollars or 61% of the project costs. The DOE will have invested approximately $7.8 million or 39% of the project costs. Strictly on the basis of royalty and tax revenue generated, the NDP DOE project has been a success. The total taxes and royalties for the current wells in the project are estimated to be about $23 million or almost three times the DOE investment in the project.

Clearly the success of this project can be measured in many ways. These include the additional production from the Nash Draw field, the discovery of other nearby fields, the use of 3-D, and deviated and horizontal drilling to identify, develop, and produce from reservoirs with limited surface access or even from the multiple return that the Federal government has and will continue to realize from its investment in this type of “real world” petroleum technology.

All of the advanced technologies developed in the NDP project have been applied by Strata to other nearby projects which we believe could ultimately result in the recovery of 2 to 5 million BOE. To date a large 500,000 acre area (i.e. U.S. Secretary of Interior’s Potash Enclave) in southeastern New Mexico has been closed to vertical oil and gas exploration, drilling, and development. This area is estimated to contain over 1 billion BOE. The exploration, development, and production tools developed through this project may allow at least a portion of this resource potential to be realized in the near term. The production of these petroleum resources is of vital importance to our Nation. At $50.00 per barrel, the economic benefit could exceed $50 billion. Given that most of these reserves would be produced from lands owned by the Federal government, its share from royalties alone could approximate $6 billion.

EXPERIMENTAL RESULTS

No experiments were associated with this project.

TECHNOLOGY TRANSFER ACTIVITIES

The transfer of technology, data, and results from the NDP project has been a major objective of the project. Quarterly and annual technical reports have been submitted to the DOE to document progress made in the NDP project. In addition to the reports submitted to the DOE, details of the technologies developed and results obtained in the NDP project have been reported at various conferences and in technical papers. A list of the annual progress reports and technical papers resulting from the NDP project is provided in the Reference section of this report. Representatives from Strata Production Co. and the technical team also have organized or participated in several workshops to promote the dissemination of information generated from the NDP project. A summary of the workshops is outlined below.

Characterization Workshop

In August 1996, a workshop in Roswell, NM titled "Integration of Advanced Reservoir Characterization Techniques" was sponsored by the Petroleum Recovery Research Center (PRRC) at New Mexico Tech. Strata Production Company presented an update of the early status and findings at the Nash Draw Pool project.

Fracture Stimulation Workshop

In September 1996, a conference titled: "Stimulation Design and Monitoring--Delaware Mountain Group Formations" was held at the New Mexico Junior College in Hobbs, NM. Sponsors of the Conference included the PRRC and the Petroleum Technology Transfer Council (PTTC). Strata presented the results and conclusions of the fracture stimulation design and evaluation scenario used to determine effectiveness of the well stimulation program.

Logging Workshop

In September 1997, the Department of Energy and BDM Oklahoma held a workshop in Midland, TX entitled "Advanced Applications of Wireline Logging for Improved Recovery." At the workshop, members of Strata's team presented the techniques used in developing the advanced log analysis program.

Reservoir Characterization Workshop

In September 1997, a workshop including results from the Nash Draw project was held in Hobbs, NM in conjunction with a reservoir characterization symposium coordinated by the PRRC. The geological interpretation, integration of the seismic and reservoir data, and a discussion of the reservoir petrography and composition as it relates to log analysis and reservoir productivity were covered. The full core from NDP Well #23 was also available for inspection by attendees at the presentation and workshop.

Core Workshop

In February 1998, the Nash Draw core from NDP Well #23 and associated materials were exhibited at a core workshop in Midland, TX sponsored by the Permian Basin Section/SEPM. The workshop included cores from DOE-sponsored Class projects in the Permian Basin.

Horizontal Drilling Workshop

In May 2005, Strata Production Company was selected to participate in the PTTC workshop entitled "Horizontal Drilling Updates: Permian Basin" in Midland, TX. Strata's presentation included the experiences of using extended-reach/horizontal wells to access oil reserves beneath potash mines and playa lakes that are not accessible with conventional vertical wells. Details of the drilling, cementing, completion, production, and economics of deviated/horizontal wells at the Nash Draw Pool were shared with area producers and service companies. Lessons learned at the NDP were discussed so that other producers might benefit from those experiences. A summary of this presentation and details of the workshop are available from the Southwest Region of the PTTC.[25]

Nash Draw Webpage

A Webpage was developed for the Nash Draw Project that can be accessed at http://baervan.nmt.edu/nashdraw/. The website includes a project summary, list of participants, summary of the technical progress, current activities and future plans. Hypertext links are provided to all of the annual reports that have been submitted to the DOE. The Website is also linked from the Southwest Region of the PTTC.[25]

CONCLUSIONS AND RECOMMENDATIONS

Conclusions

Conclusions drawn from the Nash Draw/DOE Project are as follow:

- A properly designed 3-D seismic program was successful in imaging the thin sands of the Brushy Canyon reservoir at the NDP.

- The Brushy Canyon reservoir at the NDP is much more complex than initially indicated by conventional geological analysis. By using limited subsurface geology, a unique model of the sand deposition cannot be created. Subsurface geology coupled with 3-D seismic and reservoir characterization can yield a useful model and define drilling targets.

- Economic analyses and simulation studies indicated that immiscible gas injection for pressure maintenance was not warranted at the NDP due to the stage of depletion in the proposed pilot area.

- The injection of miscible carbon dioxide could recover significant quantities of oil at the NDP, but a source of low-cost CO_2 was not available in the area.

- An Advanced Log Analysis technique was developed that defined additional productive zones and led to the completion of uphole zones in existing wells at the NDP. Successful workovers in 13 wells at the NDP added reserves of 332,304 barrels of oil and 640 million cubic feet of natural gas at an overall weighted average development cost of $1.87 per barrel of oil equivalent.

- Analyses of the 3-D seismic surveys indicated the presence of excellent quality reservoir in the area underneath the potash mines and playa lakes that were not accessible with conventional vertical wells. Three directional/horizontal wells have been successfully drilled and completed, and an additional two to three wells are planned.

- Drilling times for the directional/horizontal wells were longer than anticipated because of differential sticking in the partially completed K-2 zone. Sticking in the K-2 zone was minimized by the addition of lubribeads to the drilling fluid.

- When the first directional/horizontal well was fracture stimulated, crushing of conventional frac sand occurred and significant amounts of crushed frac sand was subsequently produced from the well. This problem was overcome by the use of high-strength ceramic proppant in the stimulation of all three directional/horizontal wells.

- Because of tortuosity and other possible effects, frac pressures in the horizontal wells were much higher than encountered in vertical wells at the same depth. A jetting tool used in Well # 33 to cut a groove in the horizontal section was successful in reducing frac initiation pressure. The ignition of rocket fuel to create multiple fractures in the openhole section of Well #34 was successful in reducing tortuosity which lowered the frac treating pressure.

- As of September 1, 2005, the nine wells that were part of the DOE Class III project have produced 526,947 BO and 3.04 BCFG. Total reserves from the DOE project wells are 1.3 million barrels of oil and 6.73 BCF of natural gas. The before tax return on investment for the project is slightly in excess of three to one.

- The NDP project has acceptable economics and similar projects can be economically developed as long as oil and gas prices remain over $30 per BOE (barrel of oil equivalent).

- The NDP project demonstrated that deviated and horizontal drilling can be used to develop and produce from reservoirs with limited surface access, such as beneath mining operations and areas with limited surface access.

Recommendations

- In Brushy Canyon reservoirs similar to the NDP, pressure maintenance with lean hydrocarbon gas should be considered for implementation very soon after the field is put on production.

- Enhanced recovery with CO_2 should be evaluated as an option in Delaware formations if a source of low-cost CO_2 is available.

- When planning wells which exceed 4000 feet of lateral section, consideration should be given to setting intermediate casing through the turn to mitigate differential sticking and reduce drag.

- Future research should be directed at improving the ability to use the information obtained from 3-D seismic and other tests to identify reservoir properties including porosity, thickness, saturations, and compartmentalization.

- Research should be undertaken to improve the completion of horizontal wells in complex formations such to the Delaware.

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Table 1. Reserves from DOE Project Wells

	Oil, BBLS.	Gas, MCF	Water, BBLS.
Cumulative Production to 8-1-05	526,947	3,035,684	2,132,427
Remaining Proved Developed Producing	421,586	2,054,068	1,475,608
Proved Undeveloped (Workovers)	353,026	1,642,416	561,270
	1,301,559	6,732,168	4,169,305

Table 2. Reservoir and Fluid Properties at the NDP

Discovery Date	1992
Trapping Mechanism	Stratigraphic Trap
Current Number of Wells	16
Current Production	328 BOPD + 2.93 MMCFGPD + 980 BWPD
Reservoir Depth	6600 to 7000 ft
Pay Thickness—K & L Sandstones	20 to 50 ft
Reservoir Porosity	12 to 20%
Reservoir Permeability	0.2 to 6 md
Initial Reservoir Pressure	2963 psi
Bubble Point Pressure	2677 psi
Drive Mechanism	Solution Gas Drive
Oil Gravity	42.4° API
Primary Recovery Factor	10 to 15% oil in place
Estimated Oil in Place	25 to 50 MMbbl
Reserves, Primary Recovery	2.5 to 5 MMbbl

Table 3. Porosity/Permeability Variables a and b in Eq. 1.

Zone	Description	a	b
"K" Zone	Fine-Very Fine Grain Sand	0.207655	-2.88580
"K-2" Zone	Medium-Fine Grain Sand	0.315038	-3.69966
"L" Zone	Fine Grain Sand	0.231250	-3.06330

Table 4. Output from Advanced Log Analysis

WELL INFORMATION

OPERATOR:	Strata Production Company
WELL NO.:	Nash Unit #29
FORMATION:	Nash Draw Delaware
LOCATION:	1980' FSL & 2310' FEL SECTION 13-T23S-R29E
COUNTY:	Eddy
STATE:	New Mexico
DATE:	15-MAR-1997

OUTPUT

ORIGINAL-OIL-IN-PLACE=	948,336	BBLS.
RECOVERABLE OIL =	158,372	BBLS.
	46	FEET
ORIGINAL-GAS-IN-PLACE=	1,051,704	MCFG
ORIGINAL-WATER-IN-PLACE=	2,052,545	BBLS.
RECOVERABLE WATER =	344,445	BBLS.

CALIBRATIO **INPUT** **OUTPUT**

Rt-corr=	1.10	POROSITY=	14.10%
DEPTH =	6844	Sw=	31.32%

ENTER DEPTH OF A KNOWN PRODUCING ZONE, THEN ADJUST Rt CORRECTION FACTOR TO ACHIEVE CORRECT Sw VALUE:

INPUT

MEASURED BHT=	126	F		
BHT DEPTH=	7245	FT.		
AMBIENT TEMPERATURE=	60	F		
INTERVAL TO BE CALCULATED=	6650	TO	6900	
TEMPERATURE GRADIENT=	0.9110	F/100 FEET		
VISCOSITY OF RESERVOIR FLUIDS OIL, cp =	0.6	WATER, cp =	0.8	
ESTIMATED Rlls=	0.0340			
DELAWARE Rw=	0.047	@ 70 F		
DELAWARE Rw=	0.045	@ 75 F		
PERMEABILITY TYPE=	3	TITE=1, HIGH=2, MED.=3, MANUAL =4		
CORE CALIBRATED PERMEABILITY FACTOR=	1.00			
MEASURED Rmf=	0.103	@ 75F		
CALCULATED @ 75 F	0.055	@ 75 F		
CORE CALIBRATED POROSITY FACTOR=	1.00			
Bg, OIL FORMATION VOLUME FACTOR=	1.51	RES. BBL./STB		
DRAINAGE AREA =	60	ACRES		
Rt-corr CORRECTION FACTOR =	1.10			
CUTOFF RESIDUAL OIL SATURATION =	20.00%			
ESTIMATED RECOVERY FACTOR=	16.70%			
ORIGINAL GOR=	1,109	SCFG/BO		

CUTOFF VALUES

MAXIMUM Sw VALUE =	55.00%	
MINIMUM POROSITY - OIL ZONES =	10.00%	
MINIMUM POROSITY - WATER ZONES =	8.00%	
MAXIMUM GAMMA RAY VALUE =	75	API UNITS

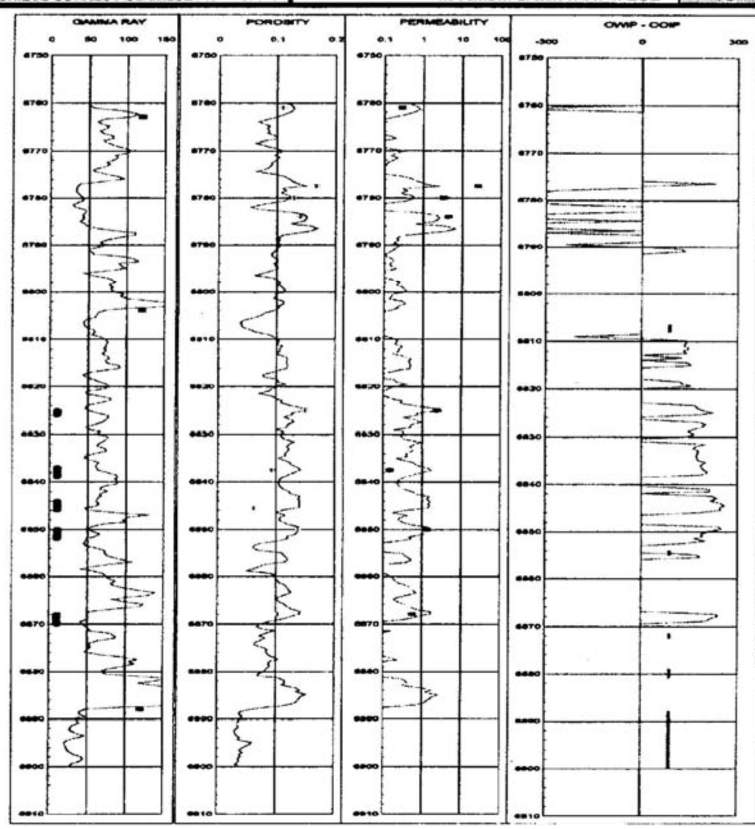


Table 5. Reservoir Simulation Forecasts for CO_2 Injection
Eleven-Year Recovery Forecasts for the NDP Pilot Area

Continued Operation

	Predicted Oil Recovery, MSTB
No CO_2 Injection	268

Miscible CO_2 Injection, 120 mcf/D

Injection Well	Predicted Oil Recovery, MSTB
1	325
5	318
6	378
10	367
14	341
Infill	365
Infill (4:1 WAG)	311
Infill*	320
Infill (Immiscible)	280

*60 mscf/D

Table 6. Drainage Areas

WELL #	1-1-98 ULTIMATE RECOVERY BBLS.	RECOVERY BO/ACRE	CALCULATED DRAINAGE AREA ACRES	SEISMIC CONTINUITY INDEX	INDICATED DRAINAGE ACRES	DESIGNED DRAINAGE ACRES	"D" DRAINAGE RATIO	"P" TOTAL TRANSMISSIVITY (OIL AND WATER)	"S" SAND SX.	P-S-D INDEX	INITIAL GOR SCFG/BO
1	61,776	2,758	22.40	1.33	29.90	40	0.7475	11.620	357	48,146	2,000
5	71,722	2,926	24.51	1.33	32.72	40	0.8180	12.826	410	59,322	1,200
6	57,525	2,627	21.90	1.33	29.23	40	0.7308	13.772	410	54,914	1,400
9	58,822	1,545	38.07	1.33	50.82	60	0.8471	4.687	1,150	62,189	1,600
10	48,162	1,613	29.86	1.33	39.86	40	0.9965	6.374	358	47,601	1,800
11	142,173	2,896	49.09	1.00	49.09	40	1.2273	14.050	410	93,151	1,200
12	34,580	2,957	11.69	1.00	11.69	60	0.1949	14.699	1,900	24,429	14,000
13	87,644	5,325	16.46	1.33	21.97	40	0.5493	22.460	540	60,493	1,500
14	89,832	3,085	29.12	1.33	38.87	40	0.9718	15.235	479	83,016	2,600
15	124,598	2,964	42.04	1.00	42.04	60	0.7006	20.890	1,860	138,104	2,700
19	134,171	2,205	60.85	1.00	60.85	60	1.0141	9.380	1,192	107,217	1,500
20	55,240	1,937	28.52	1.33	38.07	40	0.9518	7.721	410	53,549	5,900
23	41,315	1,710	24.16	1.17	28.15	60	0.4691	4.338	2,239	46,232	5,700
24	128,583	3,338	38.52	1.33	51.42	60	0.8570	10.746	1,894	122,276	2,500
25	9,721	1,178	8.25	1.33	11.02	60	0.1836	0.975	1,650	7,364	4,700
29	23,335	2,640	8.84	1.00	8.84	60	0.1473	19.609	2,169	22,785	8,100
38	27,504	1,389	19.81	1.00	19.81	60	0.3301	10.477	1,798	33,982	6,200
TOTAL	1,196,703		474.09		564.35	860.00				1,064,773	

Table 7. Bottomhole Pressure vs. Gas-Oil Ratio

WELL #	GOR 1993	BHP PSI	GOR 1994	BHP PSI	GOR 1995	BHP PSI	GOR 1996	BHP PSI	GOR 1997	BHP PSI	GOR 1998	BHP pSI
1	2.85	2100	8.54	1100	10.95	800	9.56	150	8.35	100	4.37	50
5	1.28	2800	6.38	1250	8.81	950	6.29	1275	8.47	950	9.01	900
6	1.45	2800	6.10	1280	7.64	1050	6.61	1225	6.66	1250	8.57	950
9	1.68	2800	3.01	1950	3.82	1750	12.06	400	11.60	300	8.59	200
10	0.77	2900	4.72	1550	7.23	1100	6.90	1200	13.52	500	14.06	400
11	0.96	2900	1.40	2700	4.82	1525	4.08	1800	5.26	1400	4.81	1500
12									13.03	800	15.98	500
13	1.07	2900	1.94	2400	4.96	1500	5.71	1400	6.16	1300	8.40	960
14	1.05	2900	5.79	1470	7.91	1050	12.69	400	10.81	300	9.34	200
15			1.92	2400	3.91	1725	5.74	1400	10.20	800	13.39	600
19			1.54	2600	6.87	1200	8.23	1000	5.94	1330	6.31	1250
20			2.96	2000	6.09	1300	3.80	1525	6.21	1300	7.59	1100
23					5.10	1480	7.10	1120	18.56	500	20.77	400
24					1.71	2500	3.85	1750	4.64	1550	4.26	1620
25							3.75	1760	4.45	1600	7.17	1125
29									7.00	1150	9.38	860
38									3.71	1750	5.59	1400

Table 8. Reservoir Compartments

Wells in Common Compartments	Comments
1, 6, 9, 10, 12, 14, 19, 20, 23, 25, 29 & 38	This area exhibits communication between wells, and later wells such as #12, 29, & 38 exhibited partial pressure depletion and high initial GORs.
5	This well does not exhibit major communication with neighboring wells.
11 & 13	These wells do not exhibit major communication with neighboring wells.
15	May have minor communication with #23, which would indicate a trend through #15, 23, 29, & 38.
24	This well does not exhibit communication with neighboring wells.

Table 9. Economics of Gas Injection at the NDP

	Case 1	Case 2	Case 1 vs Case 2
Gross Oil (BO)	2,031,830	2,491,679	(459,849)
Gross Gas (MCF)	10,644,603	9,635,326	1,009,277
Net Cash Flow	$49,993,023	$55,263,178	($5,270,155)
Discounted NCF	$37,360,661	$37,323,095	$37,566

Table 10. Casing Program

Casing Thread	Weight lb./ft.	Grade	Collapse psi	Burst psi	Tension k lbs.	Bending °/100 ft.
Surface						
13 3/8 in.	48	H-40	770	1730	322	
STC						
Intermediate						
8 5/8 in.	32	J-55	2530	3930	372	
LTC						
Production						
5 ½ in.	17	N-80	6280	7740	348	
LTC	Surface to 6400 ft					
5 ½ in.	17	P-110	7460	10,640	397	61
Hydril 513	6400 ft to T.D. Max O.D. 5.5 in.					

Table 11. Mud Program and Equipment

Surface to 400 feet

8.6-9.5 ppg, 29-36 vis, 8+ pH, W.L. N.C., Fresh Water with lime, gel and fiber

Intermediate 400 feet to 3100 feet

8.6-10.5 ppg, 28-31 vis, 9-10 pH, W.L. N.C., saturated brine water with paper and fiber for seepage

Production 3100 feet to T.D.

Cut brine with 3% KCL, 8.5-9.4 ppg, 28-35 vis, 10+ pH, W.L. 50-10 cc
XCD Polymer for viscosity and water loss, White Starch for water loss, Caustic for pH control, Drispac (fluid loss control), STC preservative, Nitrates (tag), KCL (shale protection)
A 10 bbl./hr. water flow was encountered at 4500 feet. This flow cut the mud, lowered the pH, reduced water loss and viscosity and increased the weight.

EPL-50 and Graphite were used to reduce drag, with these products drag was reduced by approximately 50%.

Casing Running Pill

To run casing, a 140 barrel pill was spotted from T.D. through the turn.
The pill consisted of 5 sx XCD Polymer (40 vis), 5 sx Mylo Gel, 20 sx Lubra-Glide (plastic beads), 3 drums EPL-50 (extreme pressure lubricant), 6 sx graphite.
Casing was run to T.D. with no problems, at T.D. the hole was circulated and the pill displaced, the pipe drag became excessive and was not moved during cementing.

Table 12. Mud Properties

0-400 ft	Fresh Water	Gel & Lime
400-3055 ft	Brine Water	Lime, Paper, Maxiseal, Cedar Fiber, VIS-plus
3055-5600 ft	Cut Brine 9.3 ppg	Lime, EPL-50, Caustic Soda
5600-7338 ft	Cut Brine 9.3 ppg	Lime, Soda Ash, Ammonium Nitrate, XCD Polymer, Graphite, Caustic Soda, EPL-50, STC, Flozan, Defoamer
7338-T.D.	Cut Brine 9.3 ppg	+ Starch, 1.5% Diesel, Delta P, Mica, Magnafiber, Lubribeads

Typical Properties - 9.3 ppg, Vis 44, PV 10, YP 24, pH 10, Filter Cake 1/32 in., Cl 100,000, Ca 2800, Sand Trace, Solids 0.2%, Oil 1.5 %

Table 13. Directional Drilling Equipment

Typical Bottom Hole Assembly

7 7/8” BIT	0.80’
A625XP(7:8) MOTOR W/ 1.5O BENT SUB	26.74’
FLOAT SUB	2.05’
6 1/8” O.D. FLEX PONY	13.85’
UBHO SUB	1.99’
NONMETALIC COLLAR	28.93’
FLEX JOINT	30.60’
CROSS-OVER	2.16’
91 JTS. 4” F.H. DRILL PIPE	2831.53’
CROSSOVER	1.53’
37 JTS. 4 ½” X.H. HEAVY WEIGHT DRILL PIPE	1111.45’
JARS	30.97’
5 JTS. 4 ½” X.H. HEAVY WEIGHT DRILL PIPE	150.20’
KEYSEAT WIPER	3.97’
TOTAL	4236.77’

Table 14. Drill Bits

1.	17 1/2”	Security	EDT	305 ft.	8.5 hrs.		
2.	11”	Security	ERA	2807 ft.	97.75 hrs.		
3.	7 7/8”	Hughes	38-E	281 ft.	10.25 hrs.		
4.	7 7/8”	Reed	HP-52	927 ft.	47 hrs.	19.72 ft./hr.	
5.	7 7/8”	Reed	HP-52	1982 ft.	98.25 hrs.	20.2 ft./hr.	
6.	7 7/8”	Reed	HP-53	406 ft.	35.5 hrs.	11.4 ft./hr.	Loose Bearing
7.	7 7/8”	Reed	HP-53	270 ft.	25 hrs.	10.8 ft./hr.	
8.	7 7/8”	Reed	HP-52	560 ft.	62.25 hrs.	9.0 ft./hr.	
9.	7 7/8”	Reed	HP-52	1248 ft.	103.8 hrs.	12.03 ft./hr.	-3/8” out of gauge
10.	7 7/8”	Hughes	MS30C	381 ft.	48 hrs.	7.94 ft./hr.	-3 /8” out of gauge
11.	7 7/8”	Reed	HP-52	258 ft.	24.5 hrs.	10.5 ft./hr.	-1/8” out of gauge
12.	7 7/8”	Reed	HP-52	318 ft.	29 hrs.	11 ft./hr.	-3/16” out of gauge
13.	7 7/8”	Reed	HP-52	461 ft.	29.8 hrs.	15.5 ft./hr.	-1/8” out of gauge

619.6 Rotating Hours – 25.82 Days (55%)

7 7/8”	Reed	HP-52BK	+600 ft.	+60 hrs.	+10 ft./hr.	-1/8” out of gauge
7 7/8”	Dowdco	PDC	+750 ft.	+50 hrs.	+15 ft./hr.	Body washed

Table 15. Cementing NDP Wells #33 and #36

Surface

425 sx. Premium Plus w/ 2% CaCl, did not circulate
Ran 1” tubing and cemented to surface with 86 sx. Premium Plus

Intermediate

810 sx. 35/65 Pozmix “C” w/ 6% D-20, 10 #/sx. D-44, 0.25% D-130, 2% D-46
200 sx. Premium Plus w/ 2% S-1
Circulated 288 sx.
Fluid Caliper – 1367 cu. ft., 12 ½” hole, 73% washout

Long String

20 Barrels Chemical Wash ahead of each stage
1st Stage – 600 sx. 50/50 Pozmix “C” w/ 3% D-44, 1.5 GPS D-600, .05 GPS D-47, 3% D-174
Circulated 150 sx.
D.V. Tool at 6448 ft.
2nd Stage – 400 sx. 50/50 Pozmix “C” w/ 5% D-44, 2% D-167, 2% D-65, 2% D-46, 3% D-174
Circulated show of Cement
D.V. Tool at 4433 ft.
3rd Stage – 725 sx. 50/50 Pozmix “C” w/ 5% D-44, 2% D-167, 2% D-65, 2% D-46, 3% D-174
Estimated T.O.C. at 2400 ft.

Table 16. Cementing NDP Well #34

Surface

600 sx. Premium Plus w/ 2% CaCl & ¼ lb./sx. Celloflake, circulate 100 sacks

Intermediate

800 sx. 35/65 Pozmix “C” w/ 6% D-20, 5% D-44, ¼ lb./sx. D-29
200 sx. Premium Plus w/ 2% S-1, ¼ lb./sx. D-29
Circulated 288 sx.

Long String

20 Barrels Chemical Wash ahead
50 bbls. CemNet with the first 50 bbls. of cement
900 sx. LiteCRETE Blend
39/61 (D961/D124) + 1% bwob D153 + ¼ lb./sx. D-29 + gpsb D604AM + 0.03 gpsb M45 + 0.15 gpsb D801
(CemPlus/Lite Blend - Antisetteling - Cello Flake - Salt Blend - Antifoam - Retarder)
Mixed at 10.5 ppg, Yield 2.22 cu. Ft./sx.
Compressive strength 1450 psi in 72 hours

Estimated T.O.C. at 2400 ft.

Table 17. NDP Well #36 Zone #1 Completion

The Toe Zone 9786'to 9805' Was Completed as follows:

1. Drillout 19 feet of 4 ¾" open hole to 9805' M.D.
2. R.U. frac equipment and frac down the casing at 25 BPM with 72,000 gals. 35 #/1000 gals borate crosslinked gelled 2%KCL water, carrying 216,000 pounds of 16/30 Jordan sand. The predicted geometry is:

Propped frac half-length	438.6 feet
EOJ Hydraulic height at well	250.6 feet
Frac height from offset wells	190.0 feet
Net pressure	434 psi
Estimated Surface treating pressure	1619 psi

Table 18. NDP Well #36 Zones #2 and #3 Completion

Zones #2 and #3 were completed as follows:

1. T.I.H. with perforating guns on 2 3/8" coiled tubing, perforate 9464-9470', 6 feet, with 6 JSPF, 37 shots, using pressure activated firing head. P.O.H.
2. T.I.H. with perforating guns on 2 3/8" coiled tubing, perforate 9123-9129', 6 feet, with 6 JSPF, 37 shots, using pressure activated firing head. P.O.H.
3. R.I.H. with Mojave Tool and straddle perforations 9464-9470', breakdown and acidize with 1000 gallons 7 ½% NEFE acid.
4. Frac with 40,000 gallons 20 #/1000 gallons linear gel carrying 50,000 pounds of 20/40 jordan sand at 14 BPM.
5. Move Mojave Tool to straddle 9123-9129', breakdown and acidize with 1000 gallons 7 ½% NEFE acid.
6. Frac with 40,000 gallons 20 #/1000 gallons linear gel carrying 50,000 pounds of 20/40 jordan sand at 14 BPM.
7. PO.H. with Mojave tool and flow to recover load and test.
8. R.I.H. with 1 ¼" coiled tubing and clean out the horizontal section to T.D.
9. Put well on production.

Table 19. DOE Project Wells Cumulative Production and Developed Reserves

Well No.:	**Cum. Oil Production**	**Cum. Gas Production**	**Remaining Oil Production**	**Remaining Gas Production**	**Total Oil Reserves**	**Total Gas Reserves**
12	38,884	521,281	4,022	53,467	42,906	574,748
23	51,353	661,081	6,077	61,730	57,430	722,811
24	130,422	598,541	112,083	410,722	242,505	1,009,263
25	22,798	148,910	5,764	58,427	28,562	207,337
29	20,305	183,158	5,663	47,096	25,968	230,254
38	21,776	94,050	4,277	23,904	26,053	117,954
33	92,928	300,816	117,060	327,769	209,988	628,585
34	6,370	12,071	281,422	973,331	287,792	985,402
36	142,111	515,776	238,244	1,740,038	380,355	2,255,814
Total	**526,947**	**3,035,684**	**774,612**	**3,696,484**	**1,301,559**	**6,732,168**

Table 20. NDP Well #33 Completion

- Drillout D.V. Tool and Clean Out To T.D.
- Drill 10 Feet of Clean Formation
- Run 4 Nozzle Jet Tool to T.D., Pull Out 5 Feet and Jet Groove Perpendicular to Wellbore.
- Frac with 70,000 Gallons Yf-130sf Carrying 202,000 Pounds C-Lite @ 30 BPM
- Force Close and Recover Load

Table 21. NDP Well #34 Treating Pressures

	Tubing Pressure, kPa	Annulus Presssure, kPa
Breakdown	8,549 (1240 psi)	
Avg. rate 827 l/min. (5.2 BPM), Avg. Pressure	26,197 (3800 psi)	10,6860 (1550 psi)
Maximum Pressure	28,265 (4100 psi)	10,824 (1570 psi)
Instant Shut Down Pressure	5,722 (830 psi)	4,895 (710 psi)
5 Minute Shut-in	5,171 (750 psi)	4,343 (630 psi)
10 Minute Shut-in	4,895 (710 psi)	4,136 (600 psi)
15 Minute Shut-in	4,688 (680 psi)	3,861 (560 psi)

Table 22. Project Economics

Well No.:	**Cum. Oil Revenue**	**Cum. Gas Revenue**	**Remaining Oil Revenue @ $40.00/BO**	**Remaining Gas Revenue @ $7.00/MCFG**	**Total Revenue**
12	$915,142.39	$1,555,348.90	$160,880.00	$374,269.00	$3,005,640.29
23	$998,878.41	$1,752,131.12	$243,080.00	$432,110.00	$3,426,199.53
24	$2,803,938.16	$1,837,248.22	$4,483,320.00	$2,875,054.00	$11,999,560.38
25	$527,558.19	$476,788.50	$230,560.00	$408,989.00	$1,643,895.69
29	$430,672.98	$528,719.69	$226,520.00	$329,672.00	$1,515,584.67
33	$3,347,297.50	$1,536,561.59	$4,682,400.00	$2,294,383.00	$11,860,642.09
34	$87,634.18	0	$11,256,880.00	$6,813,317.00	$18,157,831.18
36	$4,175,251.45	$2,276,233.08	$9,529,760.00	$12,180,266.00	$28,161,510.53
38	$478,578.52	$323,061.80	$171,080.00	$167,328.00	$1,140,048.32
Total	$13,764,951.78	$10,286,092.90	$30,984,480.00	$25,875,388.00	$80,910,912.68
	Tangible Costs	**Intangible Costs**	**Equipment Costs**	**Lease Operating Costs**	**Total Expenses**
12	$297,067.28	$302,734.54	$203,057.94	$373,838.75	$1,176,698.51
23	$252,894.32	$176,341.36	$216,695.37	$587,736.68	$1,233,667.73
24	$257,490.73	$263,286.87	$267,431.12	$2,191,743.16	$2,979,951.88
25	$275,813.00	$177,868.40	$166,050.99	$378,950.41	$998,682.80
29	$278,721.92	$248,064.75	$226,219.07	$438,515.84	$1,191,521.58
33	$1,217,965.17	$1,284,977.16	$266,129.55	$1,679,006.76	$4,448,078.64
34	$1,690,109.57	$1,295,408.00	$406,397.03	$3,637,054.79	$7,028,969.39
36	$1,561,588.43	$1,581,852.95	$429,739.79	$2,878,345.50	$6,451,526.67
38	$375,317.25	$389,629.88	$222,506.43	$421,648.06	$1,409,101.62
Seismic		$2,000,000.00			$2,000,000.00
Total	$6,206,967.67	$5,720,163.91	$2,404,227.29	$12,586,839.95	$28,918,198.82
	Total Revenue	**Total Cost**	**Royalty**	**Taxes**	**Net Revenue**
12	$3,005,640.29	$1,176,698.51	$661,240.86	$195,867.52	$971,833.40
23	$3,426,199.53	$1,233,667.73	$753,763.90	$223,172.02	$1,215,595.89
24	$11,999,560.38	$2,979,951.88	$2,639,903.28	$762,138.19	$5,617,567.03
25	$1,643,895.69	$998,682.80	$361,657.05	$106,002.72	$177,553.12
29	$1,515,584.67	$1,191,521.58	$333,428.63	$98,005.70	-$107,371.24
33	$11,860,642.09	$4,448,078.64	$2,609,341.26	$747,833.24	$4,055,388.95
34	$18,157,831.18	$7,028,969.39	$3,994,722.86	$1,151,169.42	$5,982,969.51
36	$28,161,510.53	$6,451,526.67	$6,195,532.32	$1,811,169.83	$13,703,281.72
38	$1,140,048.32	$1,409,101.62	$250,810.63	$72,691.86	-$592,555.79
Seismic		$2,000,000.00			-$2,000,000.00
Total	$80,910,912.68	$28,918,198.82	$17,800,400.79	$5,168,050.49	$29,024,262.58

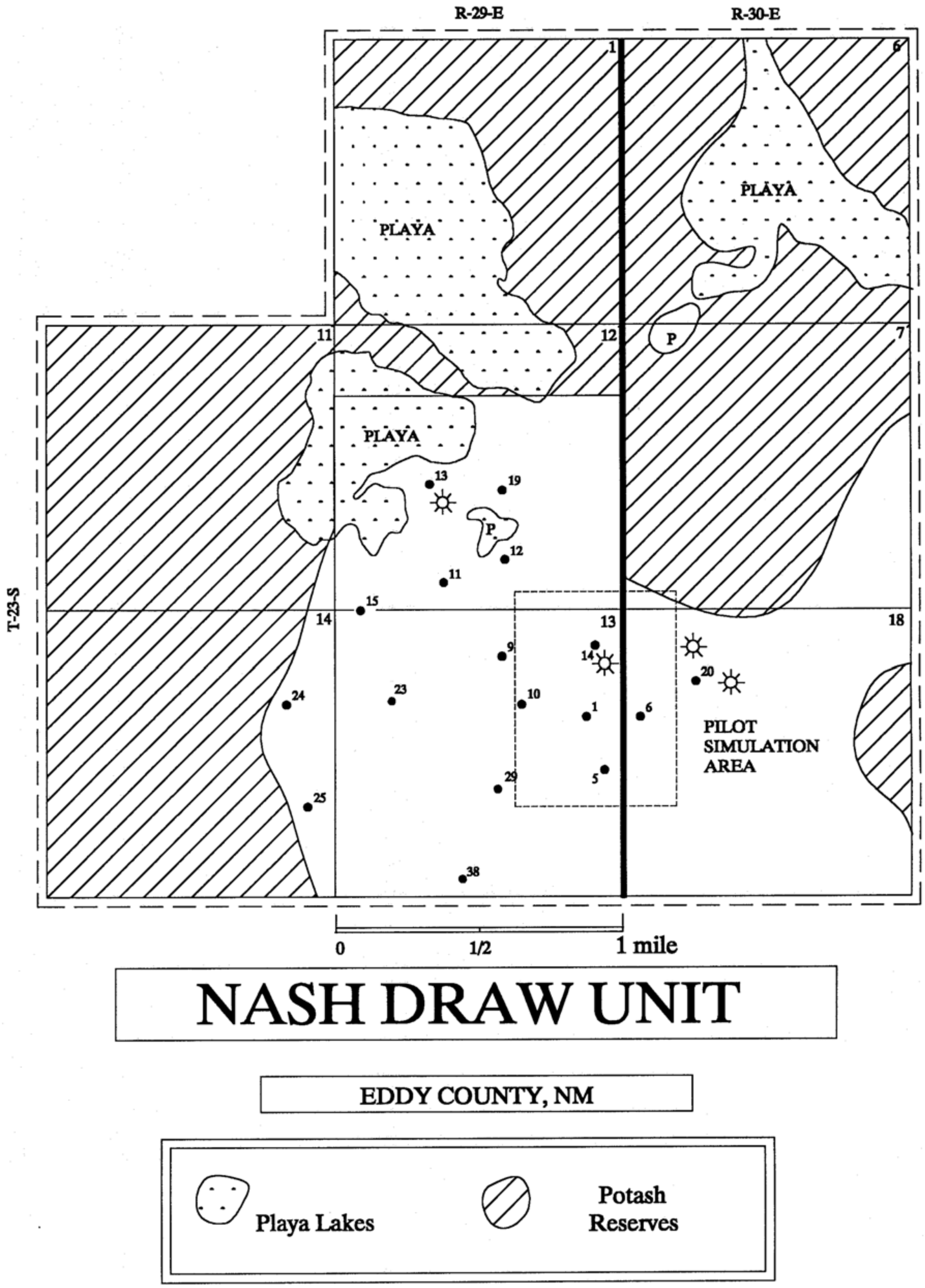


Fig. 1. Map of NDP of vertical wells showing potash and playa lakes.

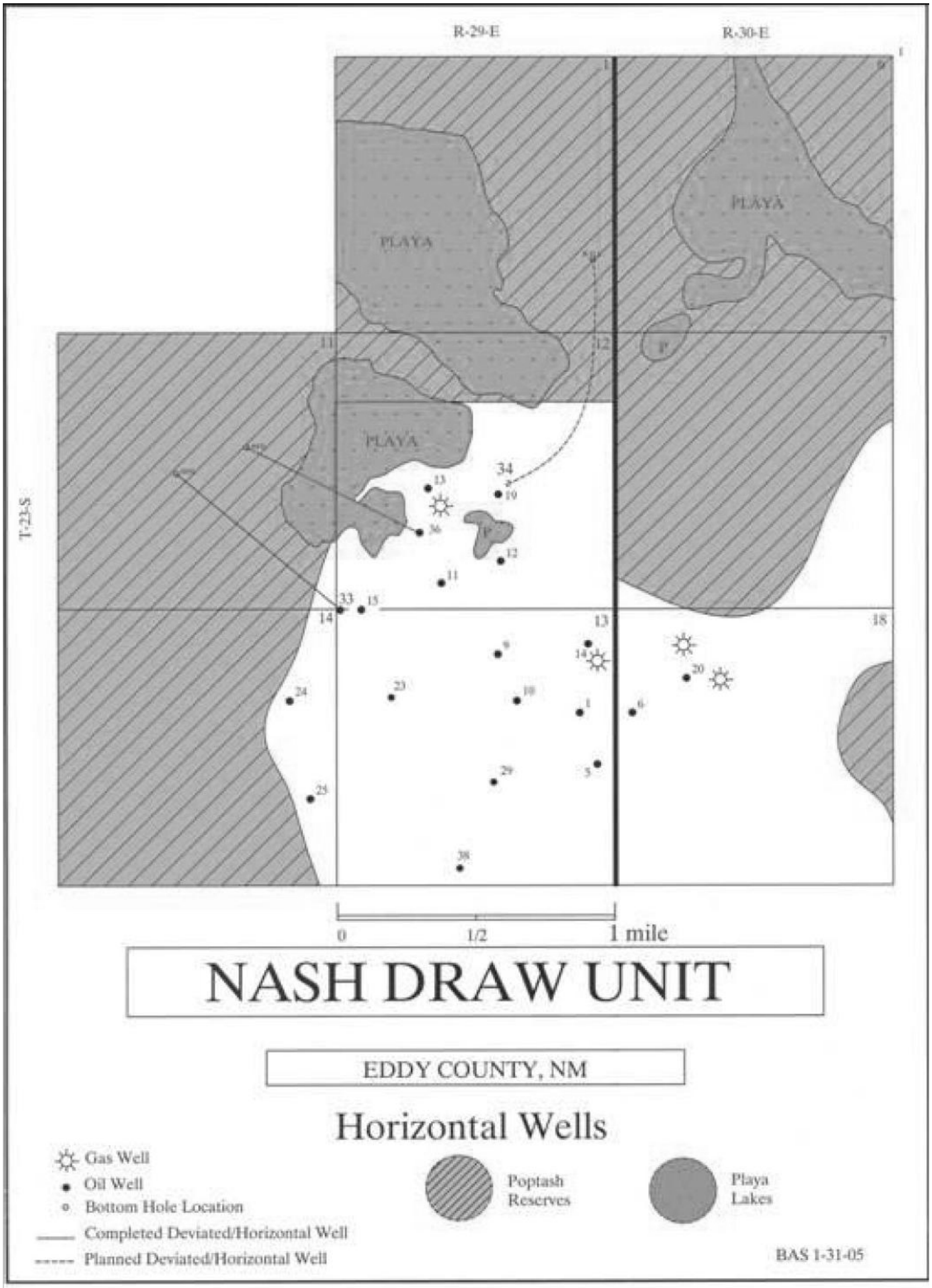


Fig. 2. Map of NDP showing horizontal wells.

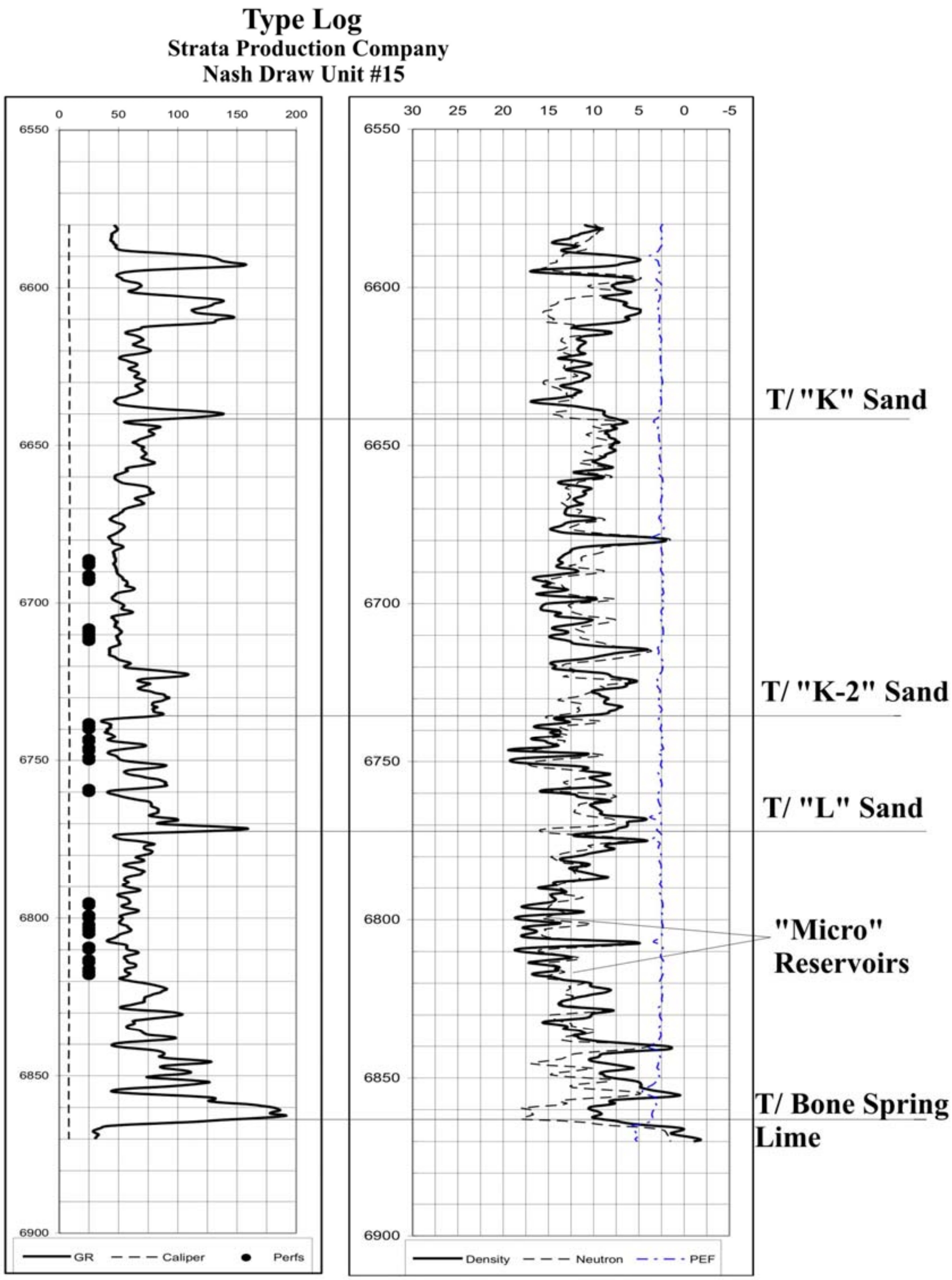


Fig. 3. Type log for NDP Well #15.

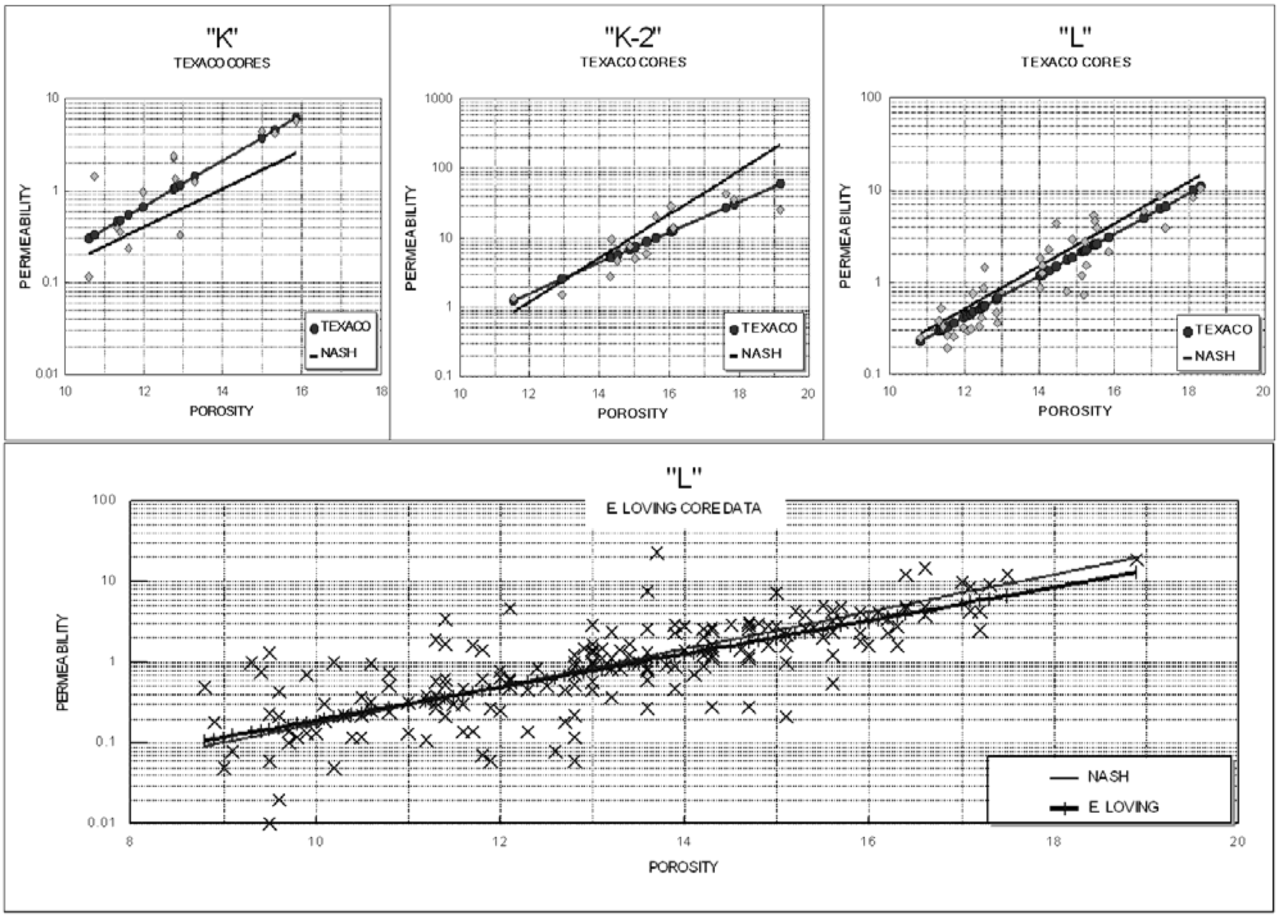


Fig. 4. Permeability vs. porosity for other Delaware fields.

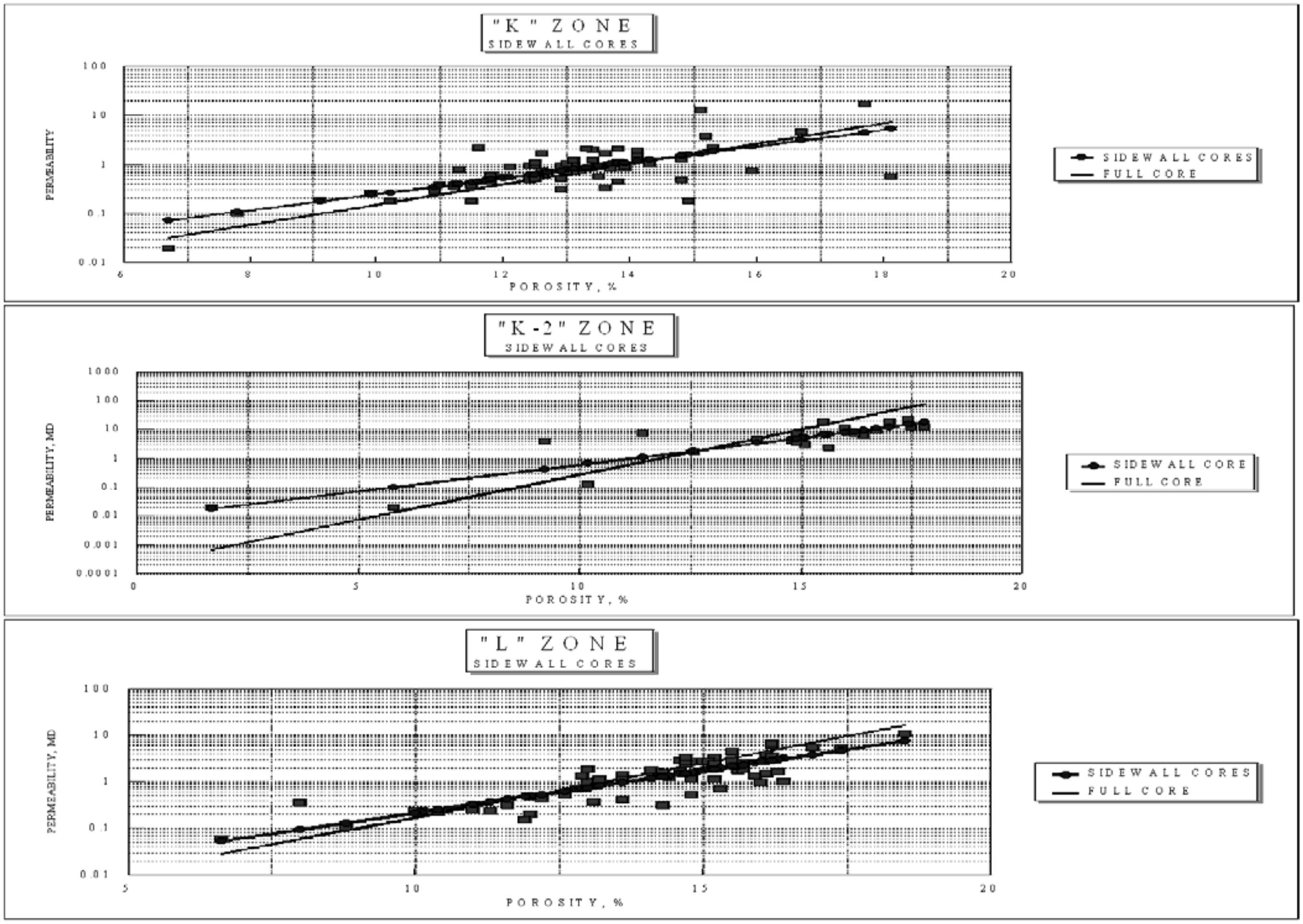
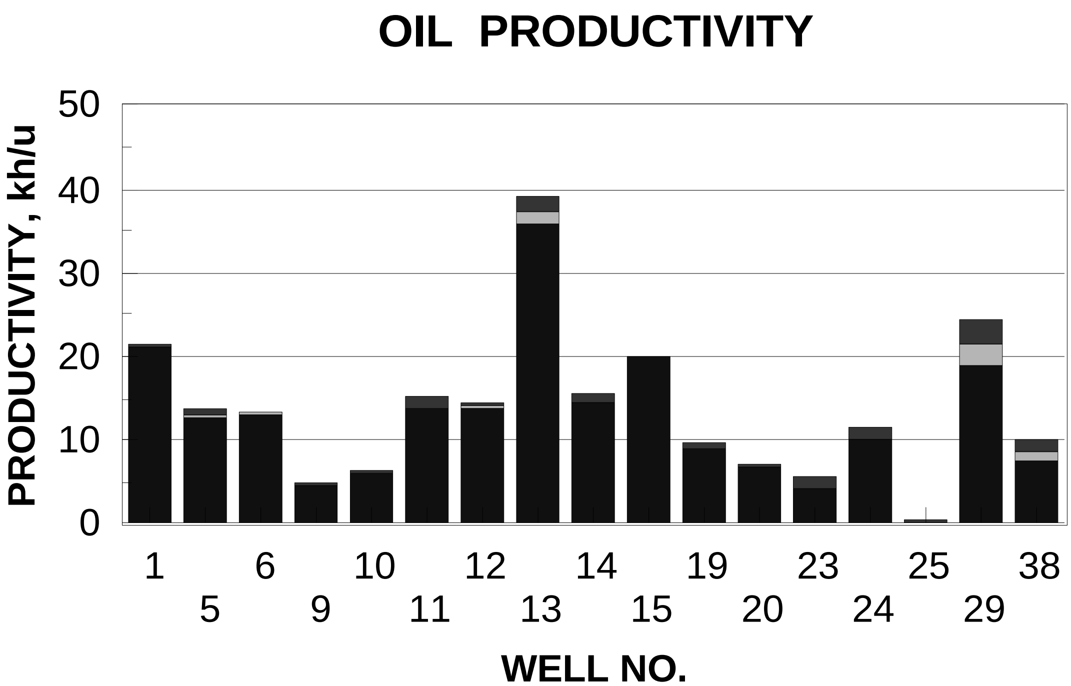


Fig. 5. NDP porosity–permeability correlations.



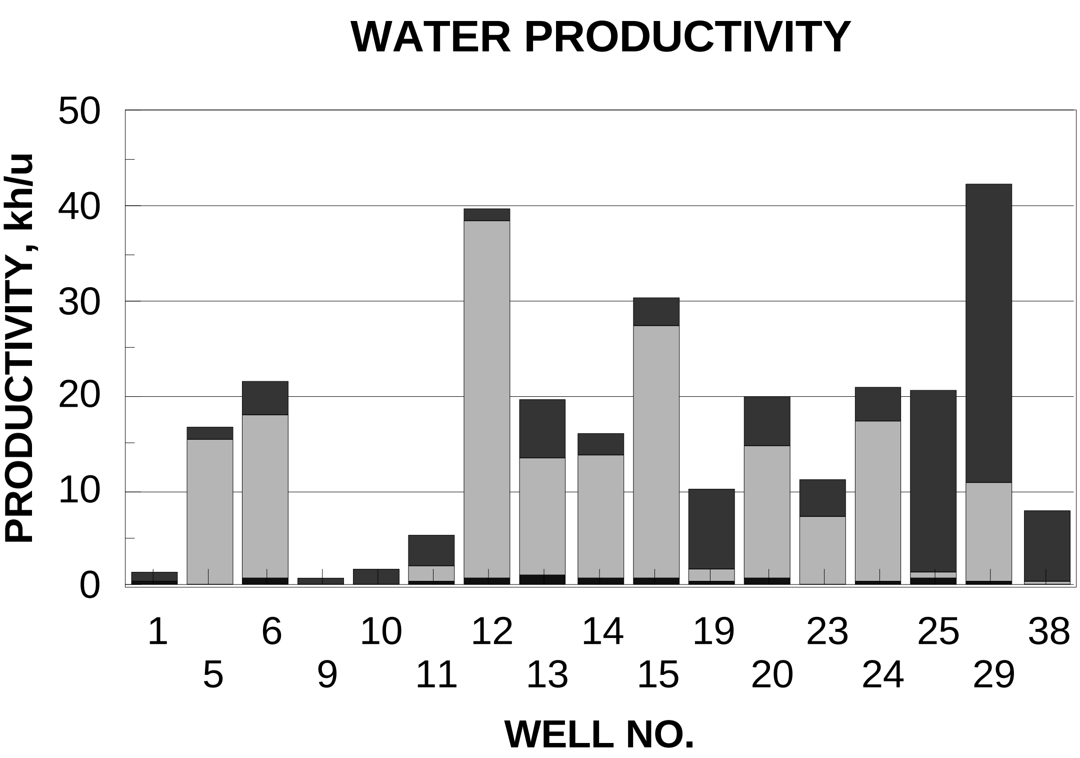


Fig. 6. Productivity of oil and water for “K,” “K-2,” “L” zones.

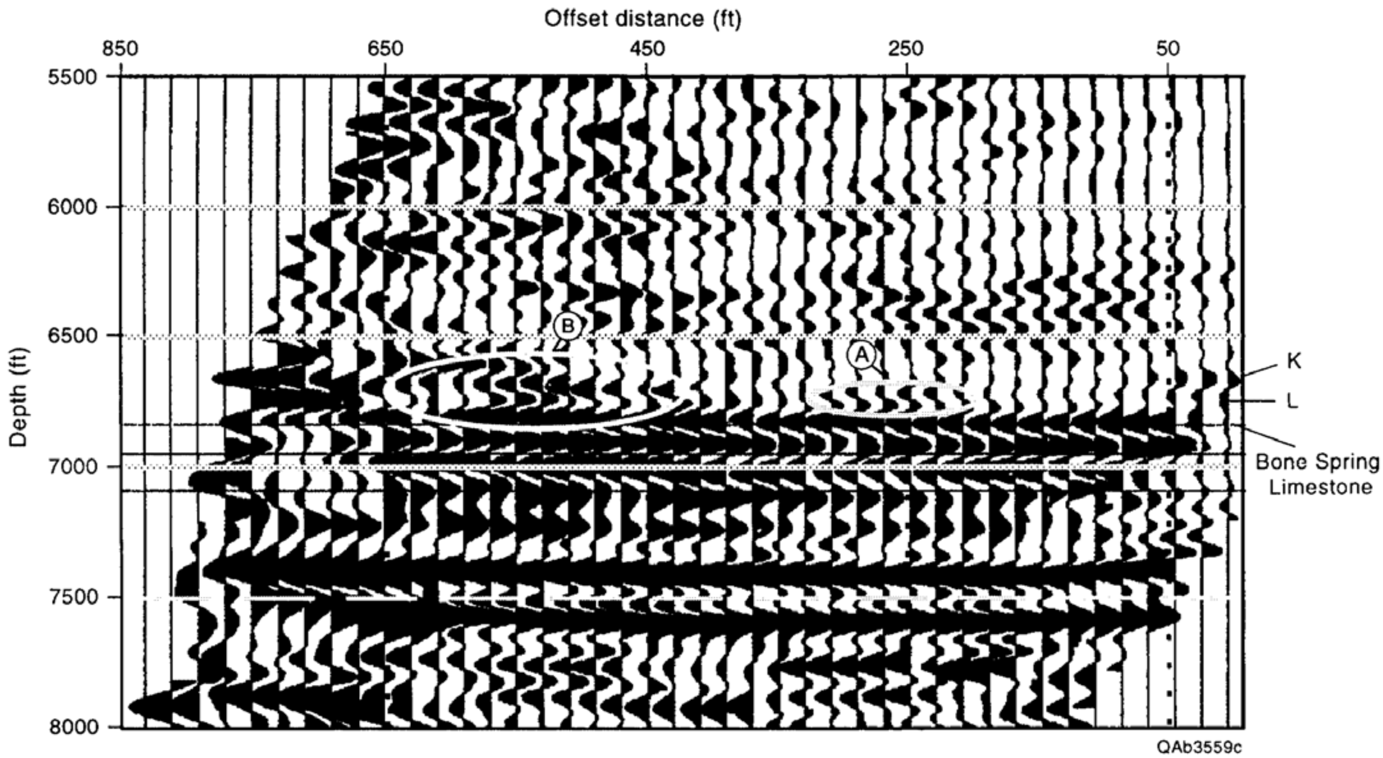


Fig. 7. VSP image of “K” peak and “L” trough.

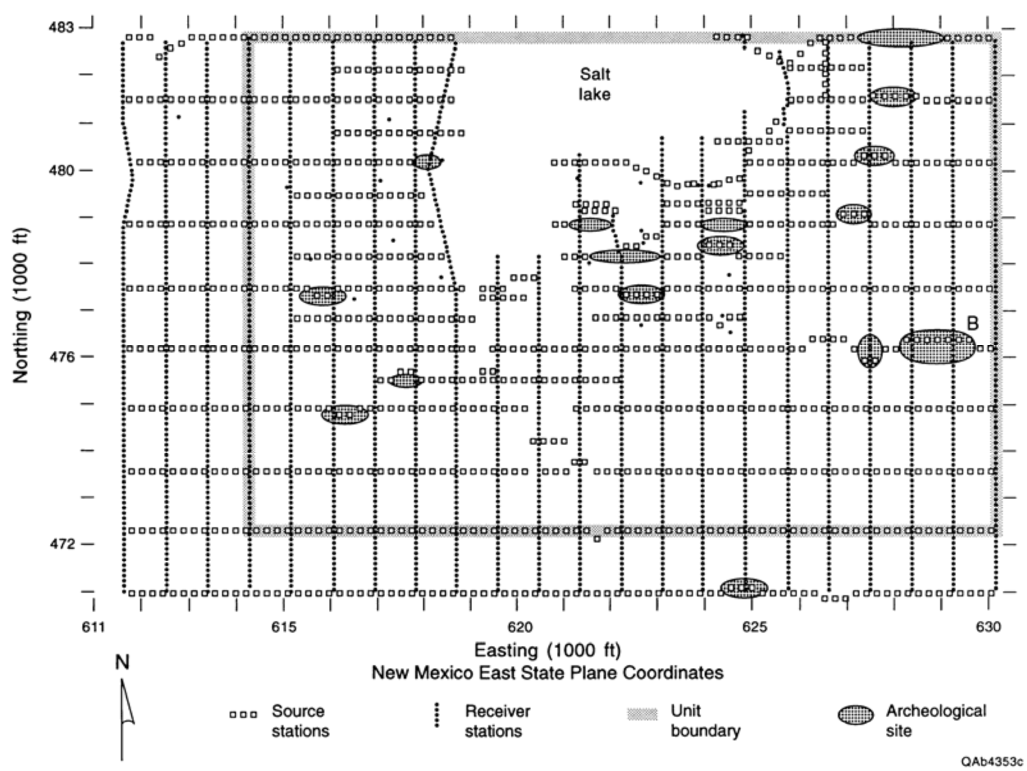


Fig. 8. Geometry used for acquisition of 3-D seismic survey.

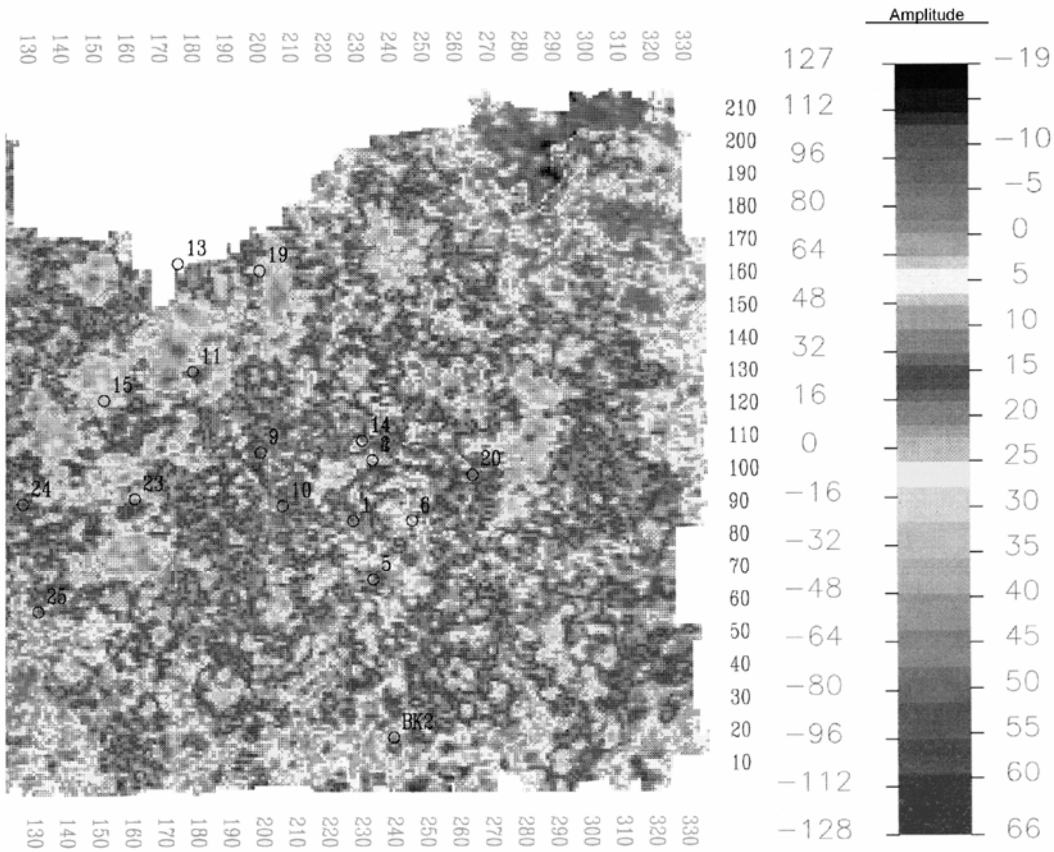


Fig. 9. Seismic amplitude of "K" sandstone.

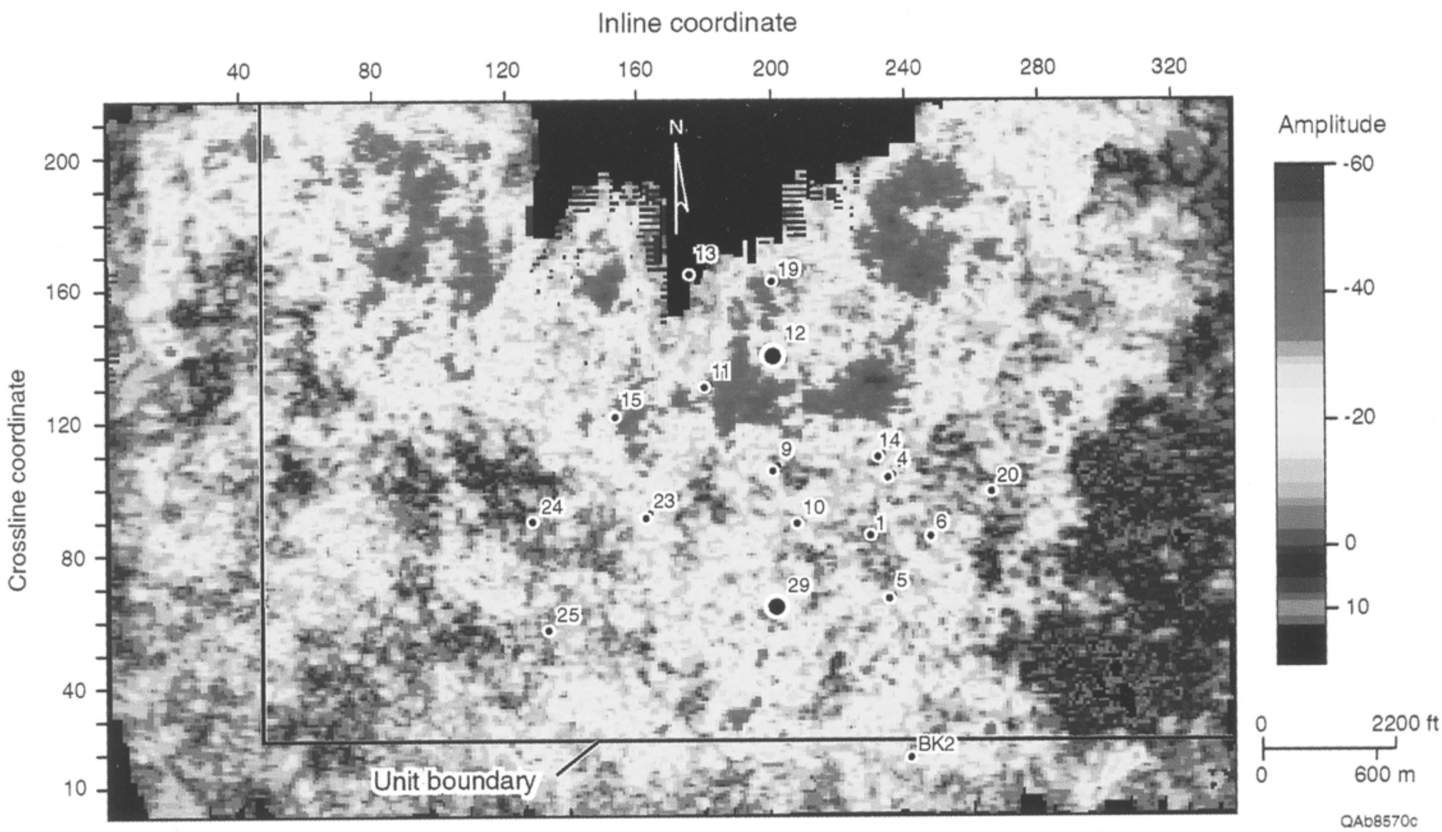


Fig. 10. Seismic amplitude of "L" sandstone.

Well Number	Reflection Amplitude	Net Pay (feet)	Total Transmissivity (oil and water)
5	-11.20	21.5	12.826
6	-19.20	25.0	13.772
9	-6.33	12.5	4.687
10	-8.73	13.5	6.374
11	-35.86	28.0	14.050
12	-31.02	37.0	14.699
14	-14.10	26.0	15.235
15	-24.98	28.0	20.890
19	-37.26	19.5	9.380
20	-12.23	20.5	7.721
23	-17.78	6.5	4.338
24	-10.74	20.0	10.746
25	-10.55	2.5	0.975
29	-32.50	31.0	19.609

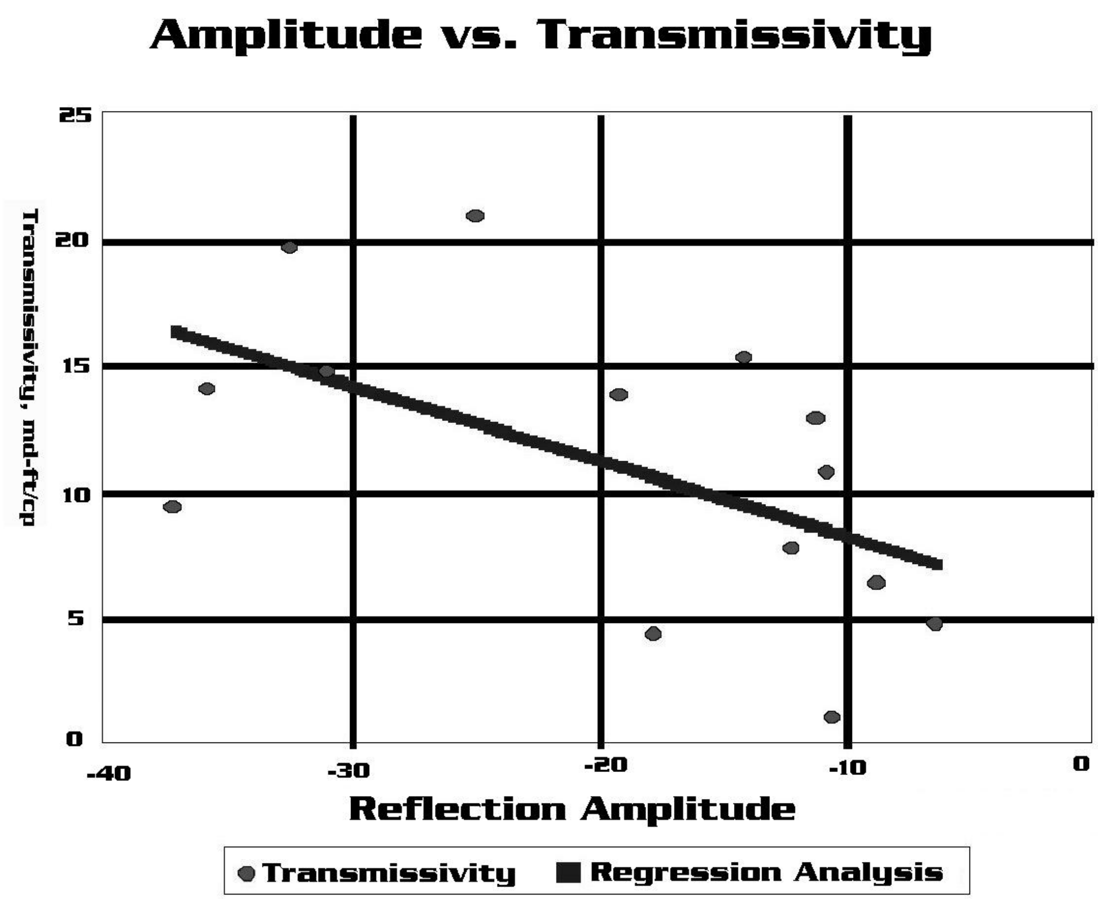


Fig. 11. “L” zone seismic amplitude vs. transmissivity.

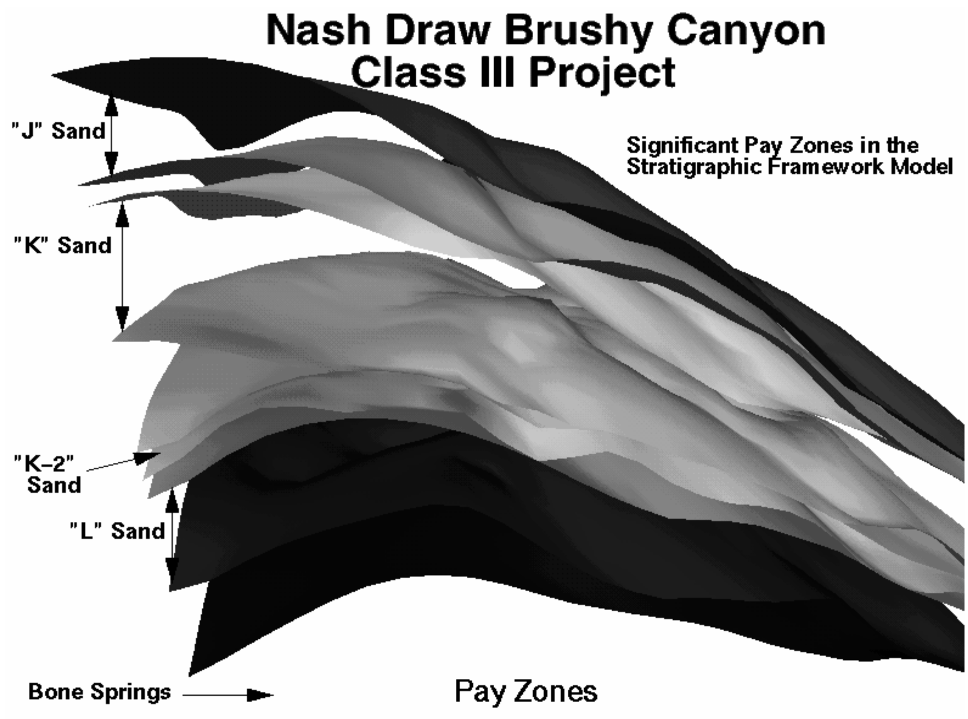


Fig. 12. Stratigraphic framework model.

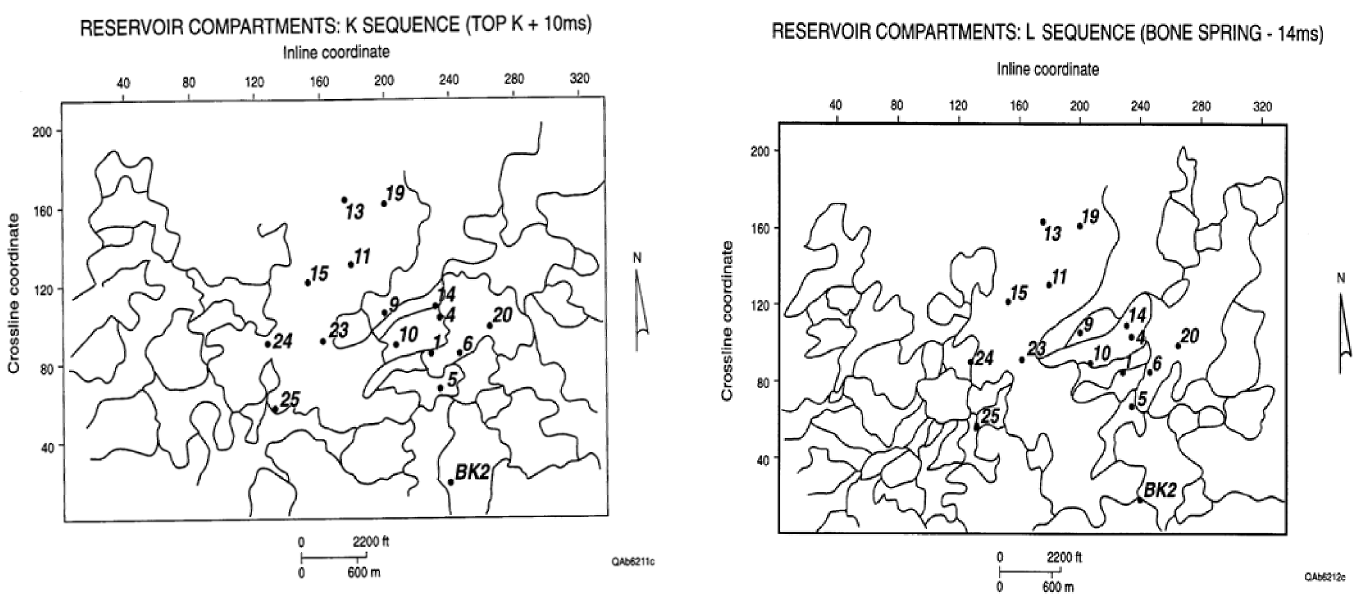


Fig. 13. Reservoir compartmentalization.

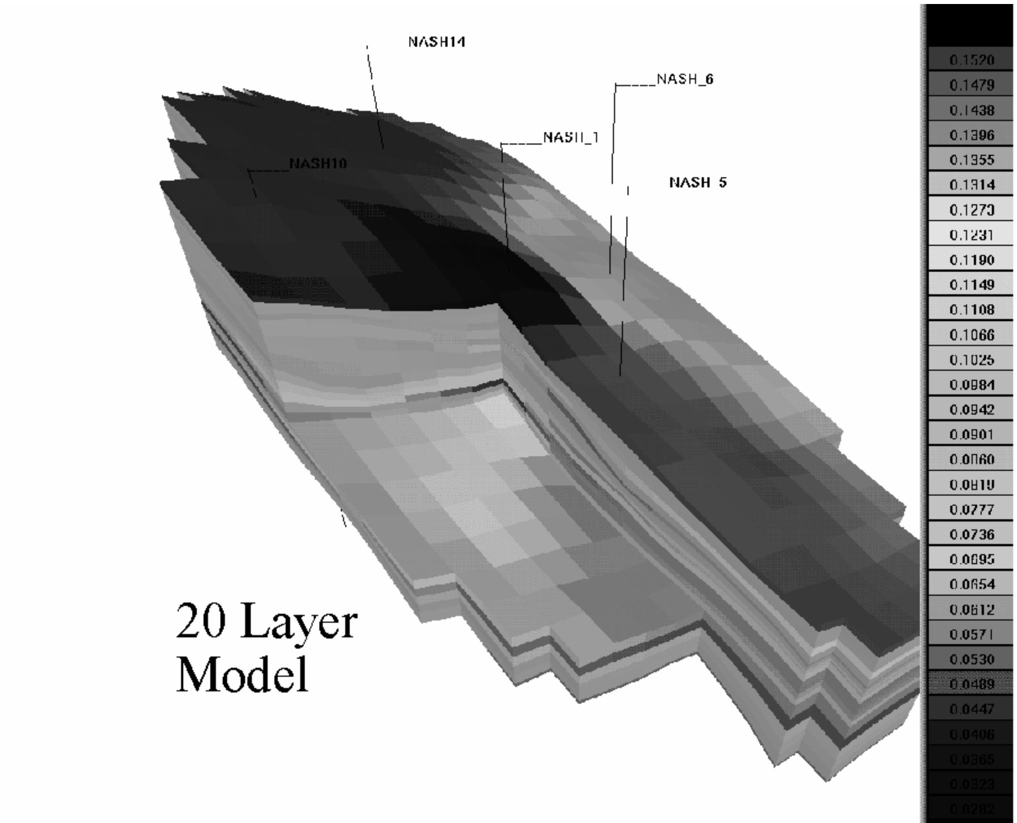


Fig. 14. Twenty-layer model.

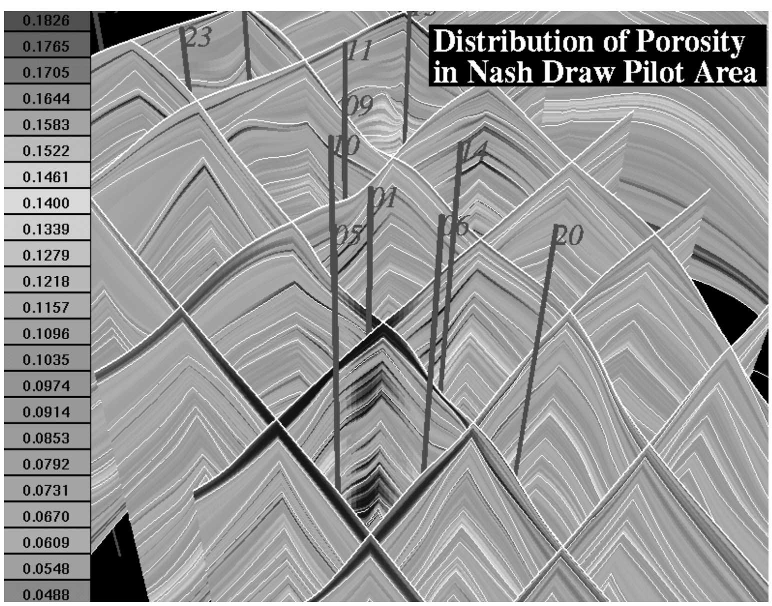


Fig. 15. Porosity distribution.

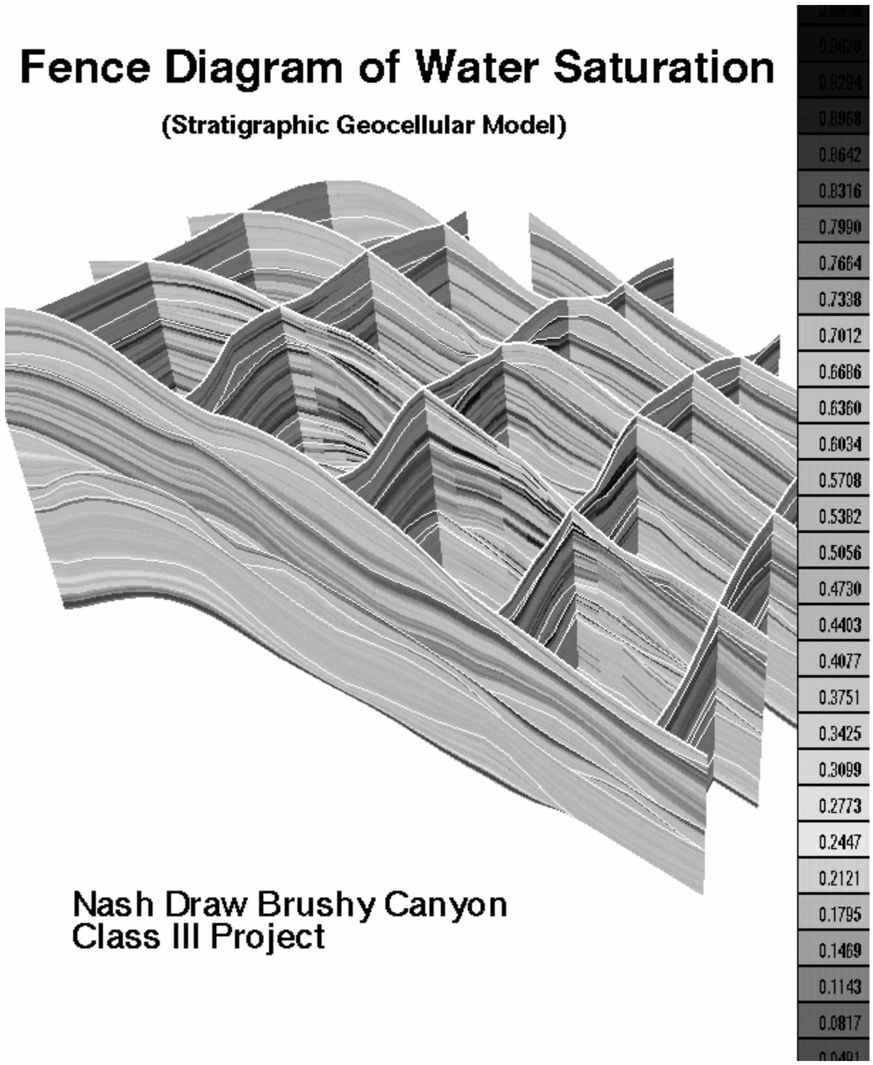


Fig. 16. Water saturation fence diagram.

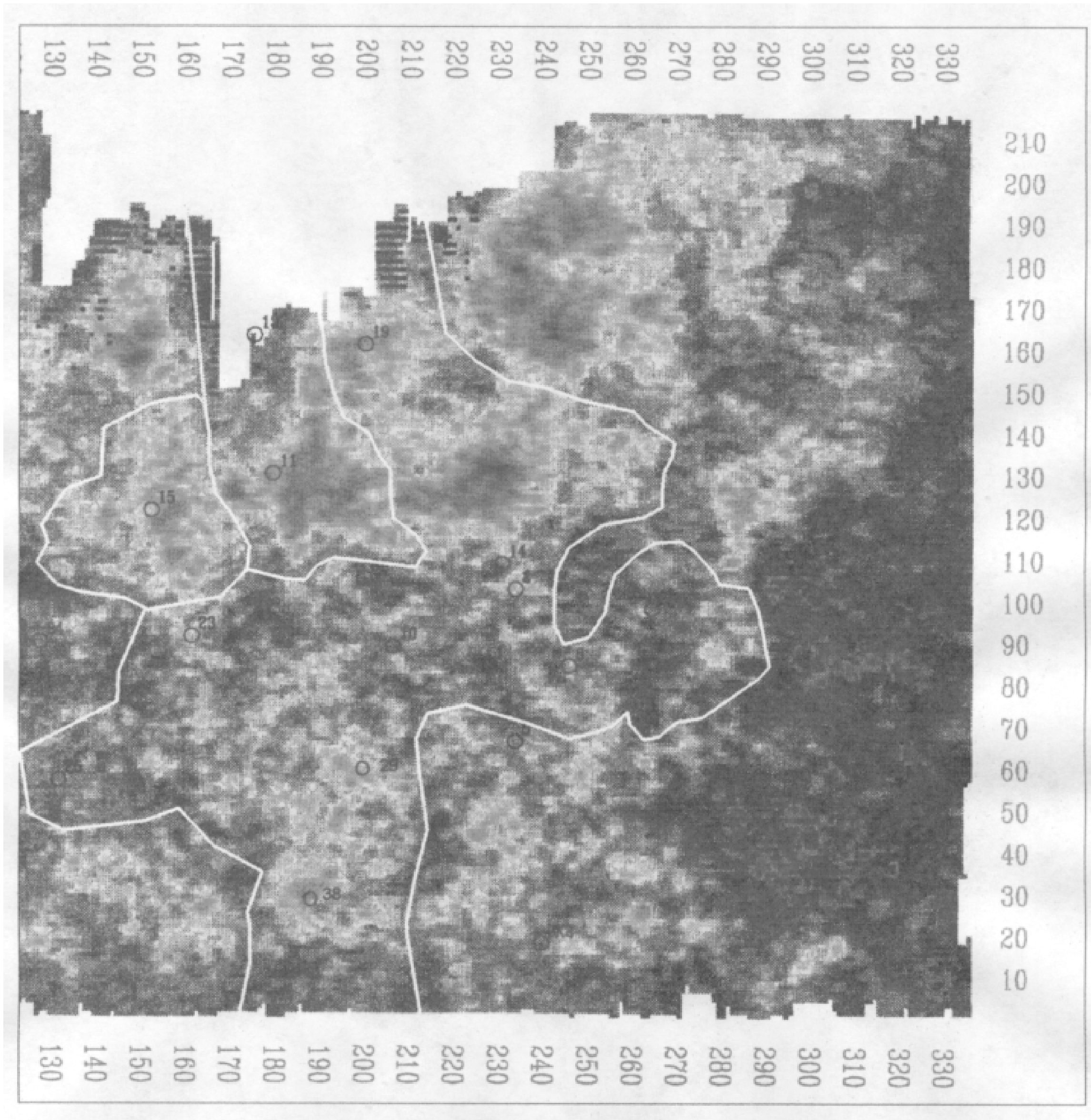


Fig. 17. Major reservoir compartments.

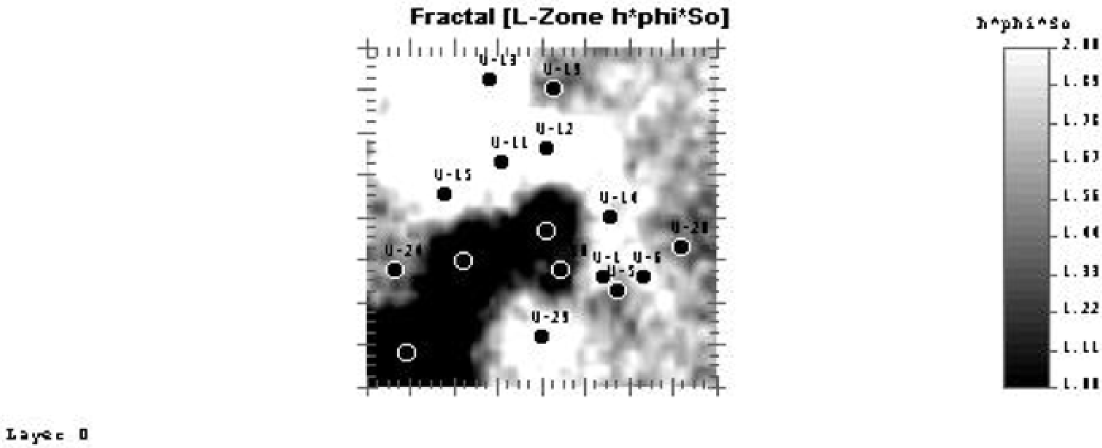


Fig. 18. Fractal hydrocarbon pore volume.

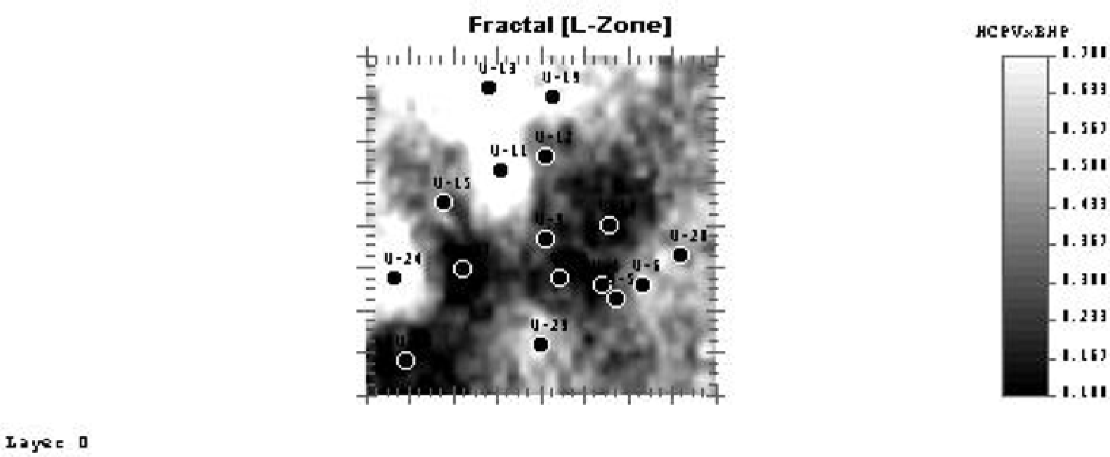


Fig. 19. Fractal HCPV conditioned with BHP.

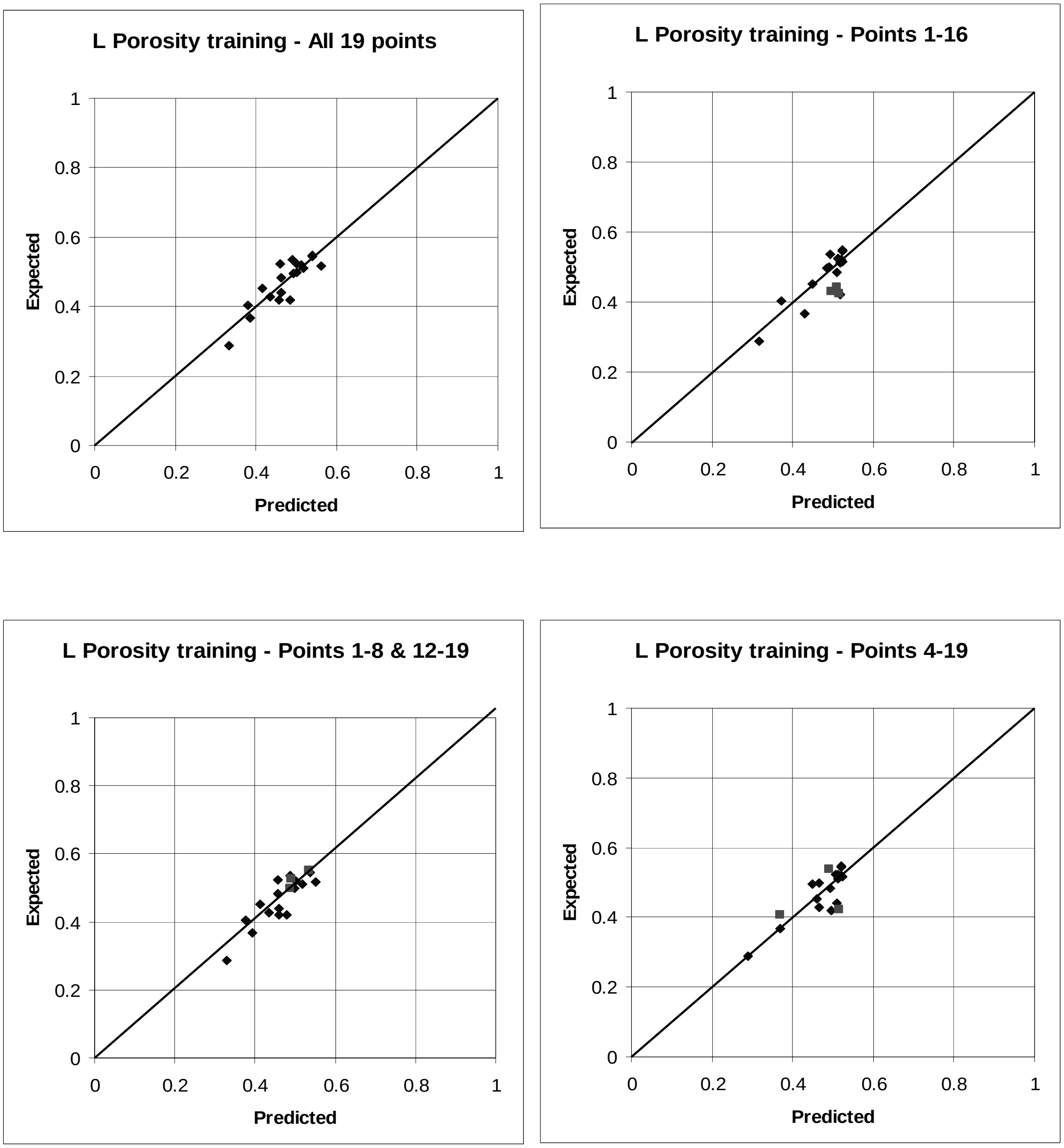


Fig. 20. Expected vs. predicted porosity for "L" zone.

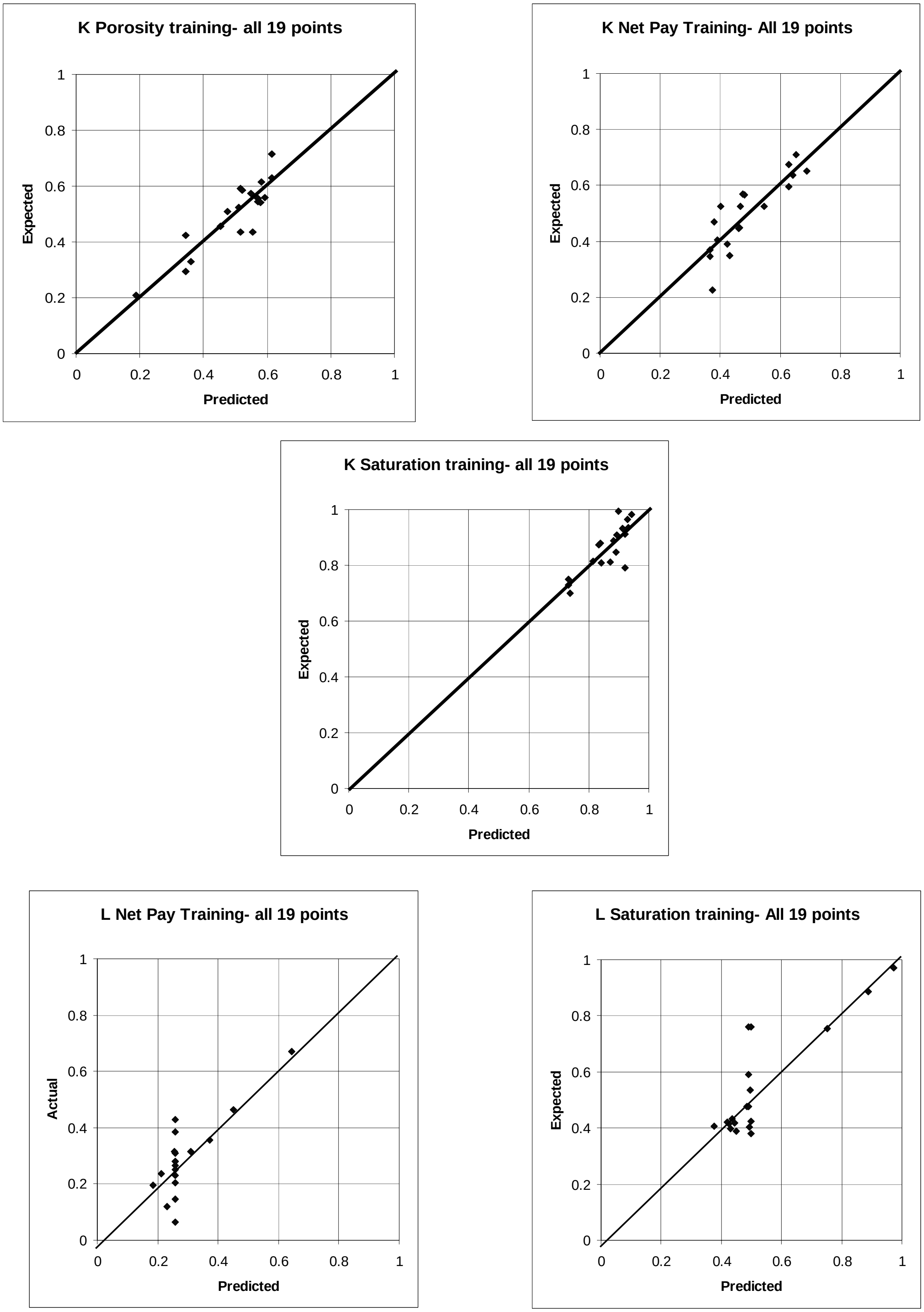


Fig. 21. Crossplots for training neural network.

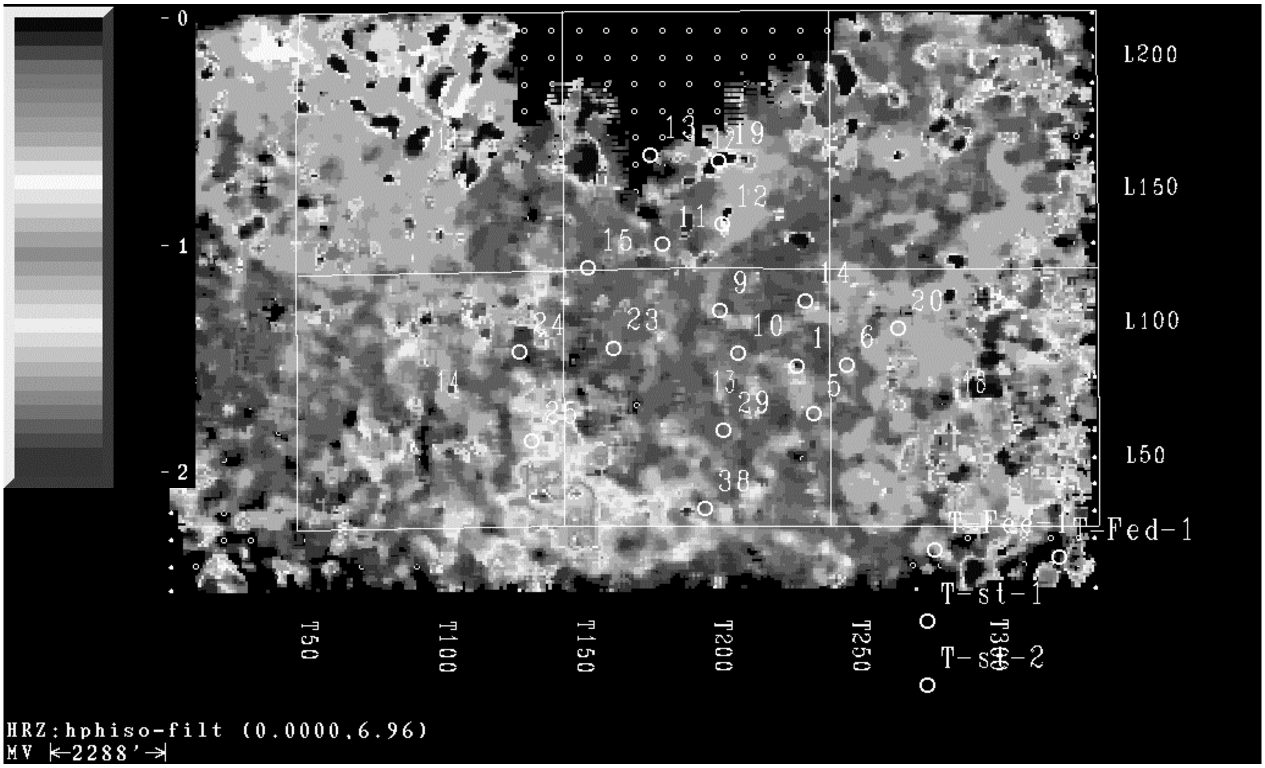


Fig. 22. Predicted HCPV from neural networks.

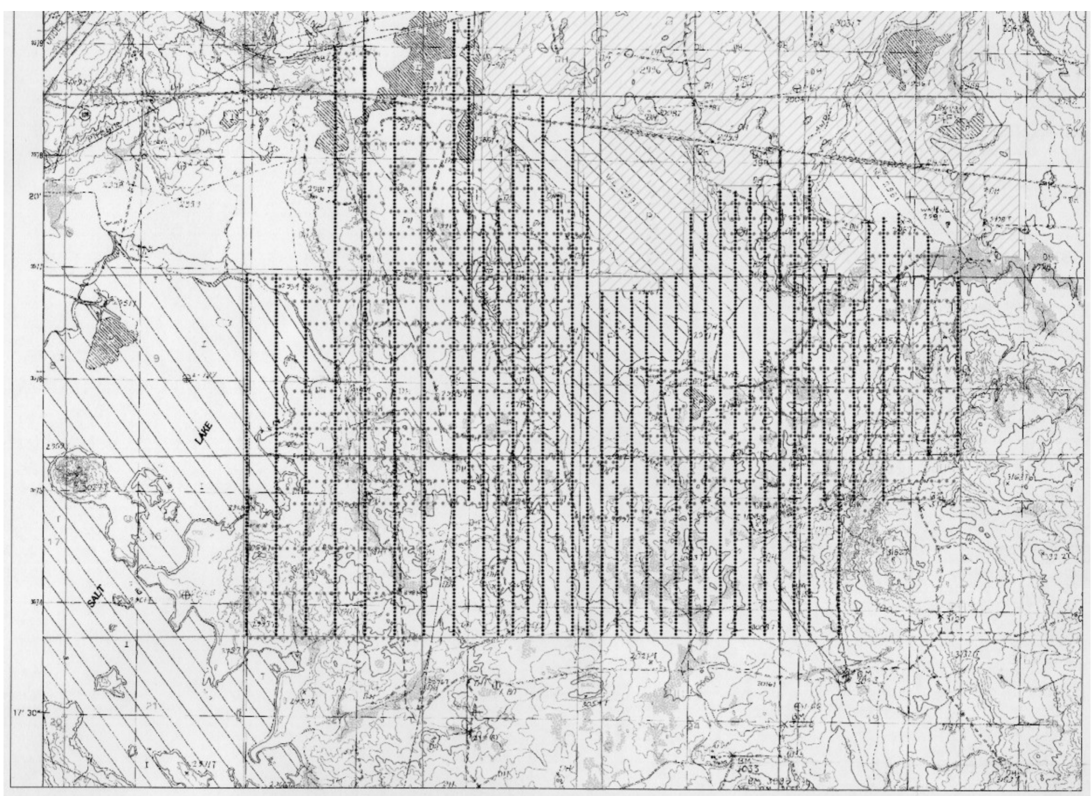


Fig. 23. Final design of second 3-D seismic survey.

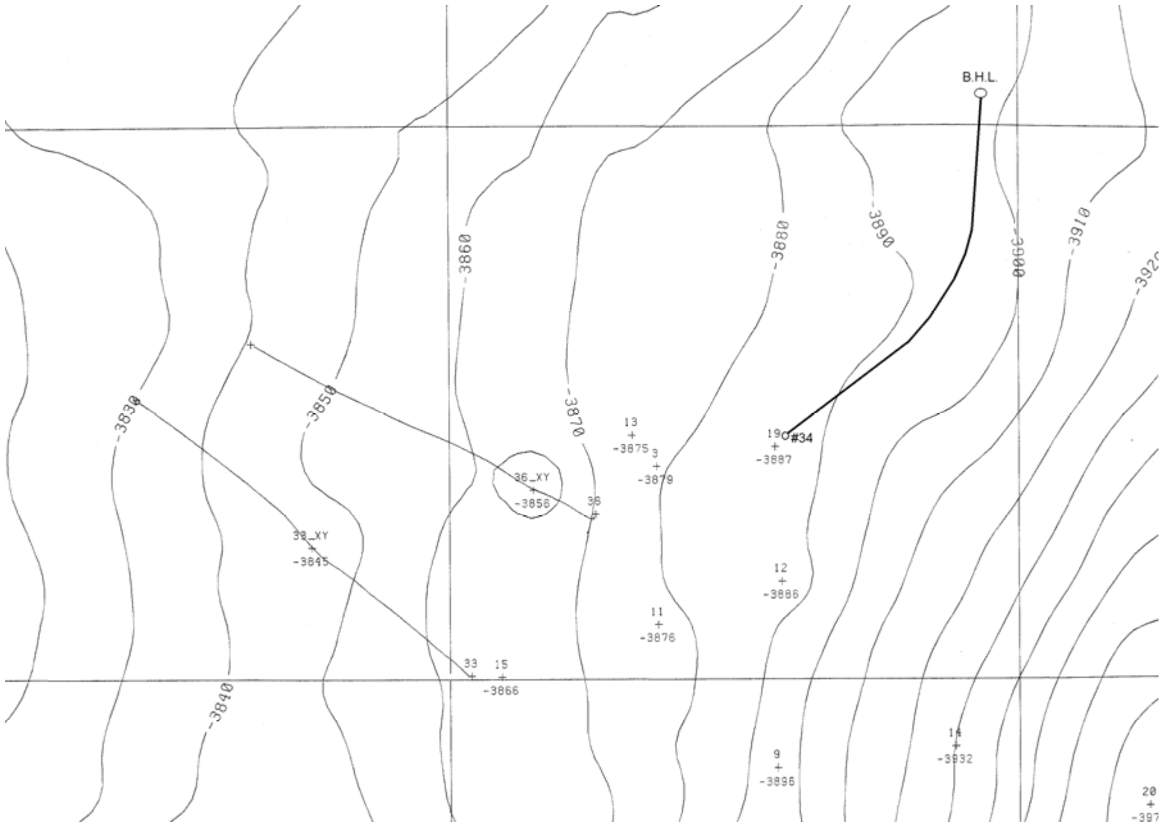


Fig. 24. Second generation structure map.

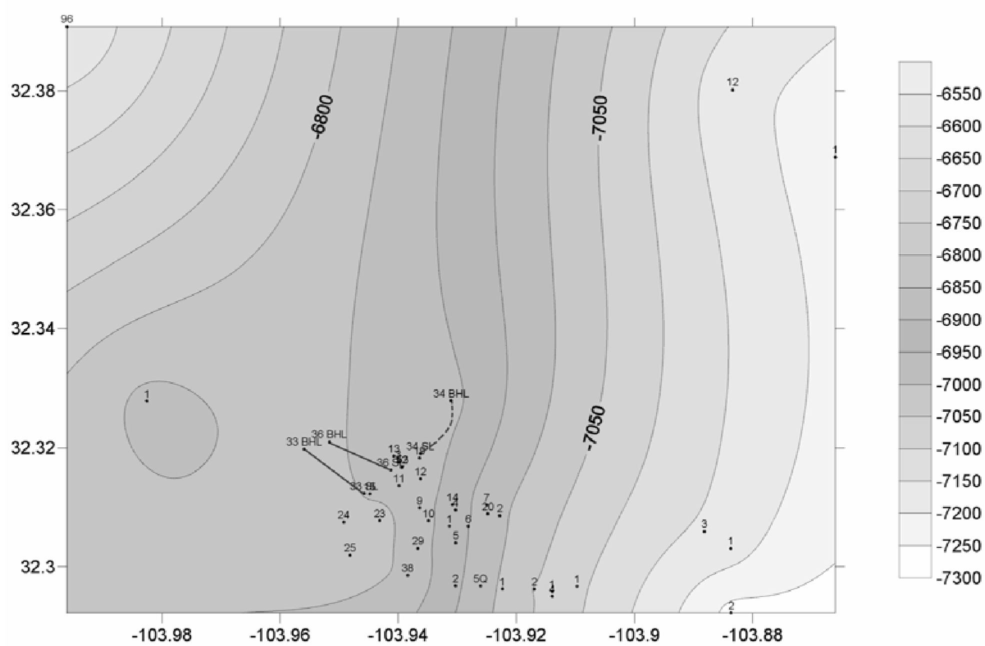


Fig. 25. Top of Bone Spring structure map.

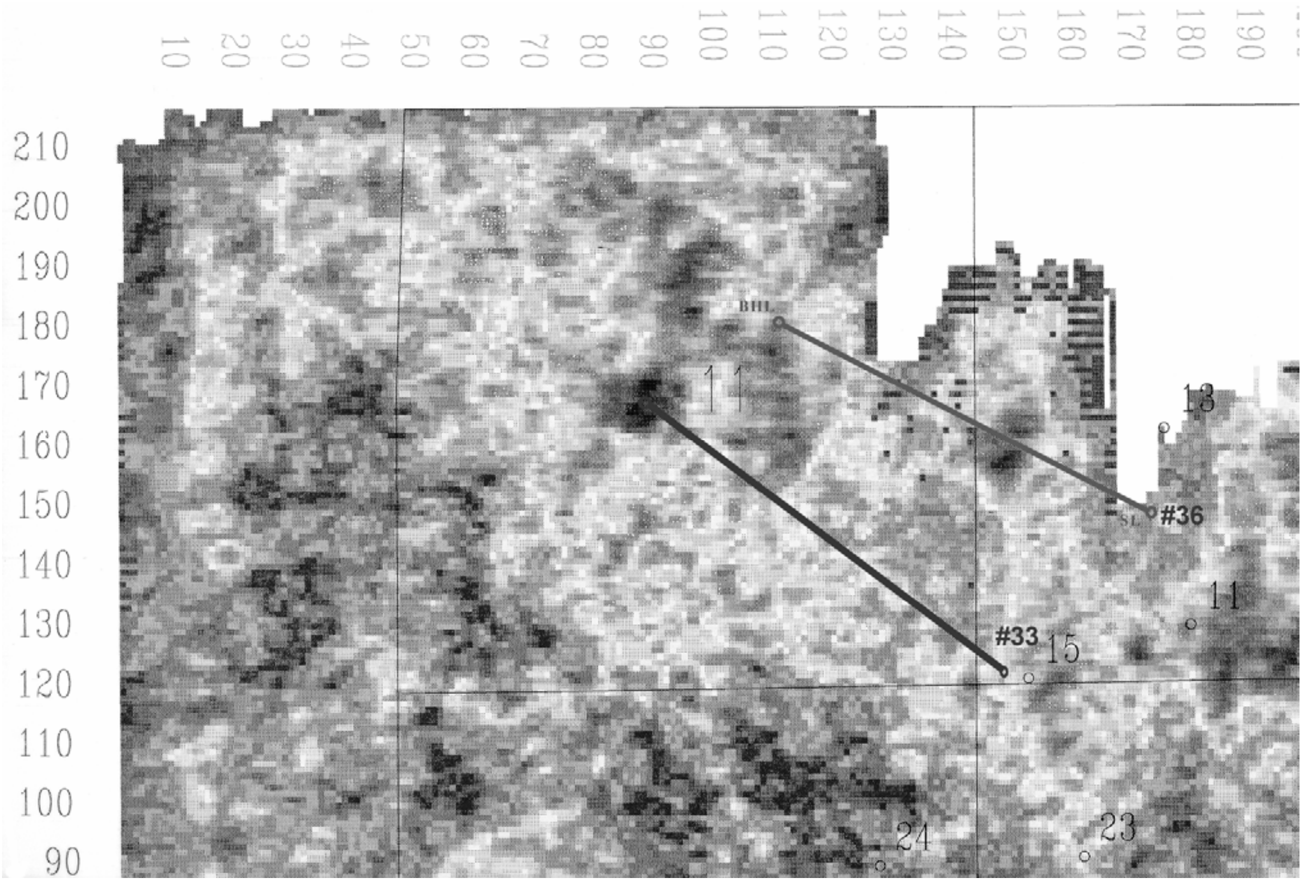


Fig. 26. “L” seismic amplitude map.

Fig. 27. Limited surface access.

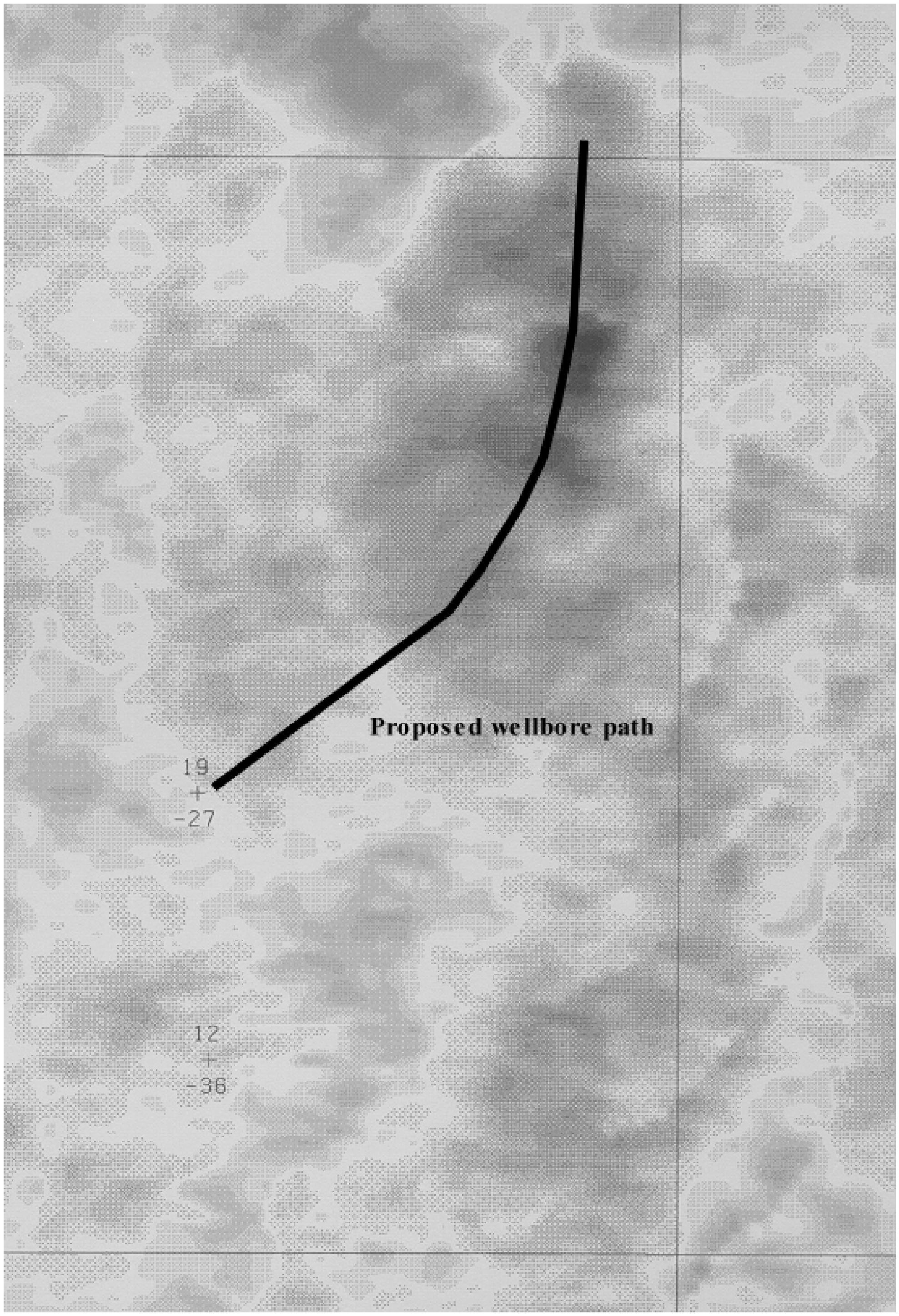


Fig. 28. Nash Draw #34 target.

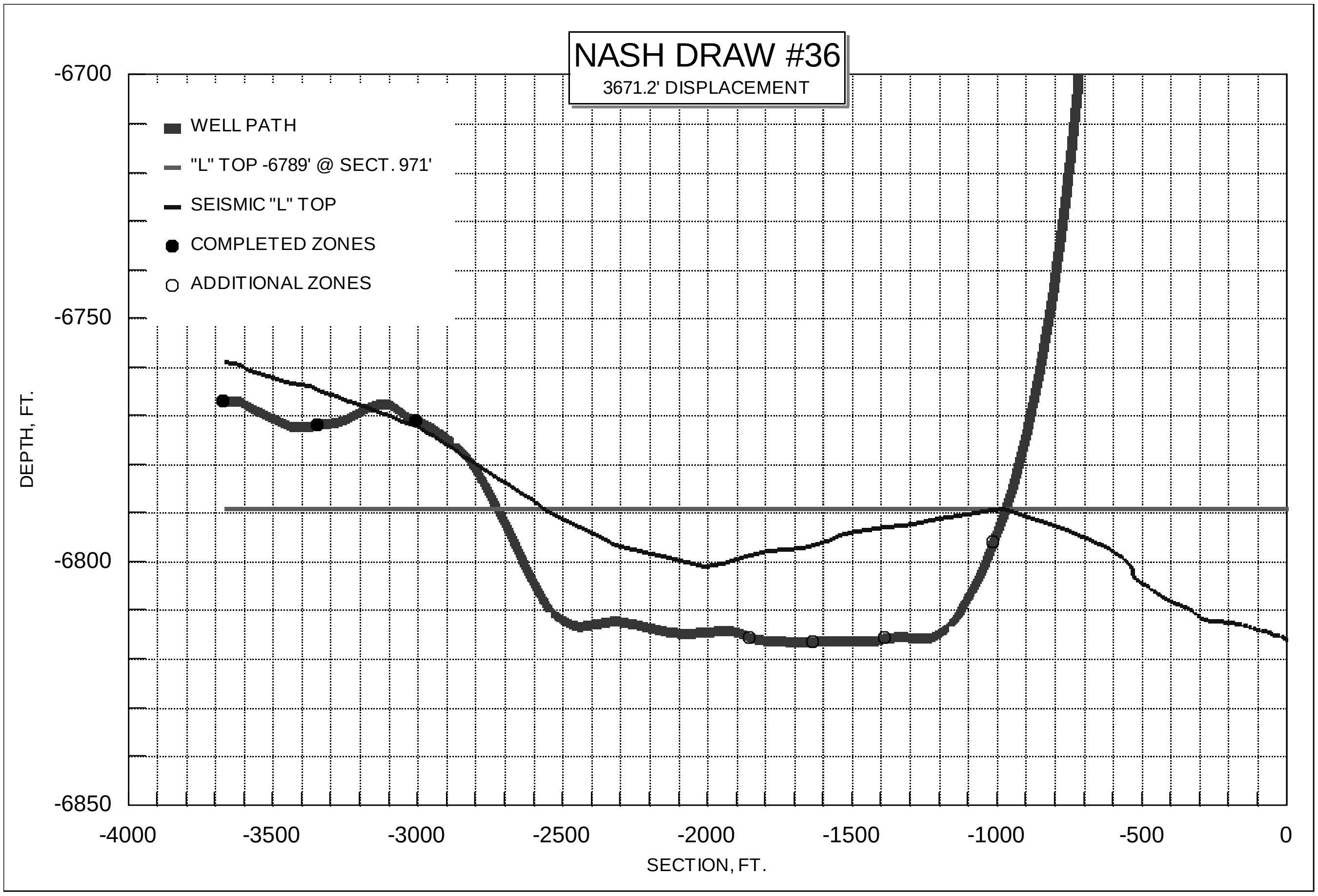


Fig. 29. NDP Well #36 toe zone completions.

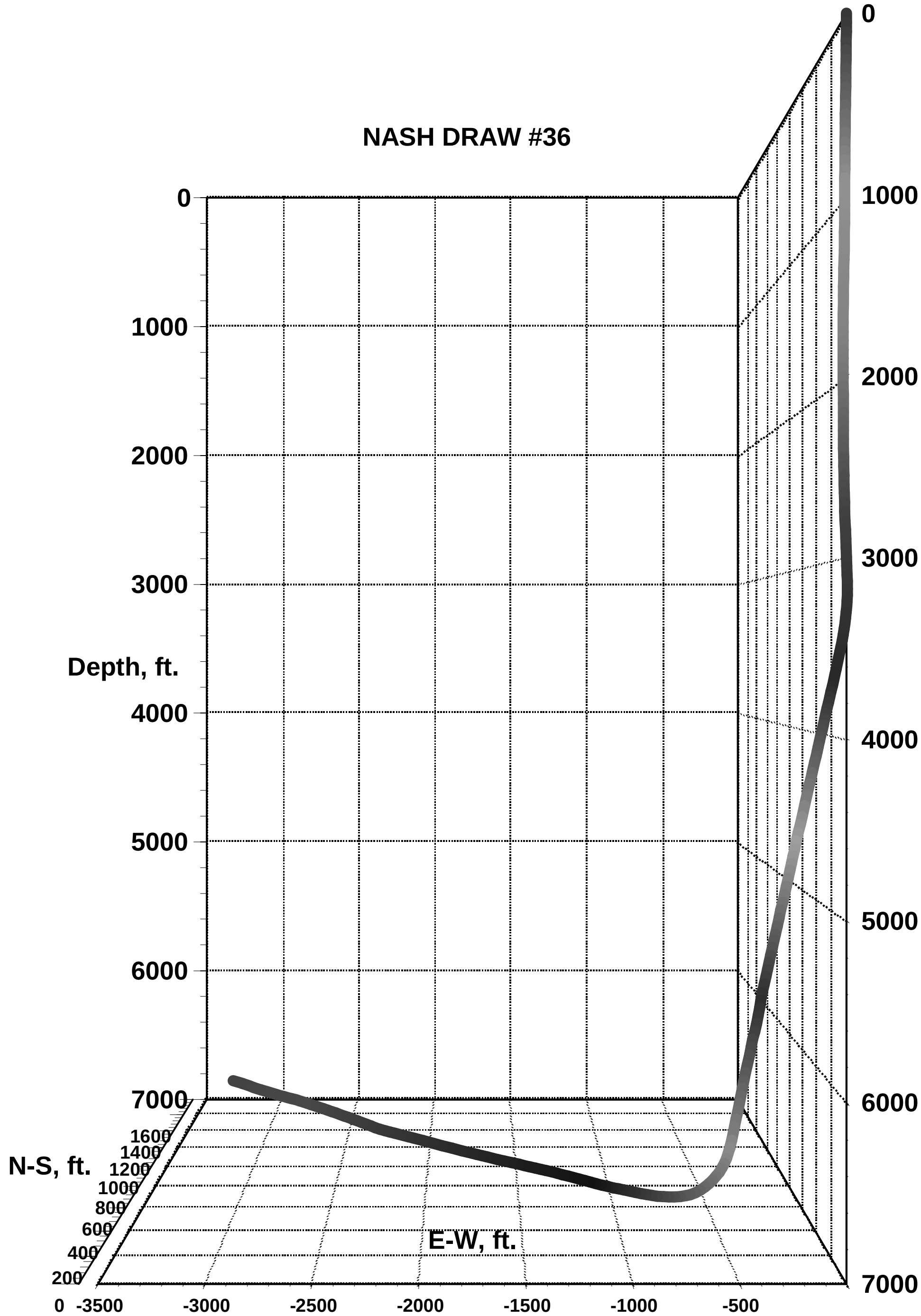


Fig. 30. NDP Well #36 final well path.

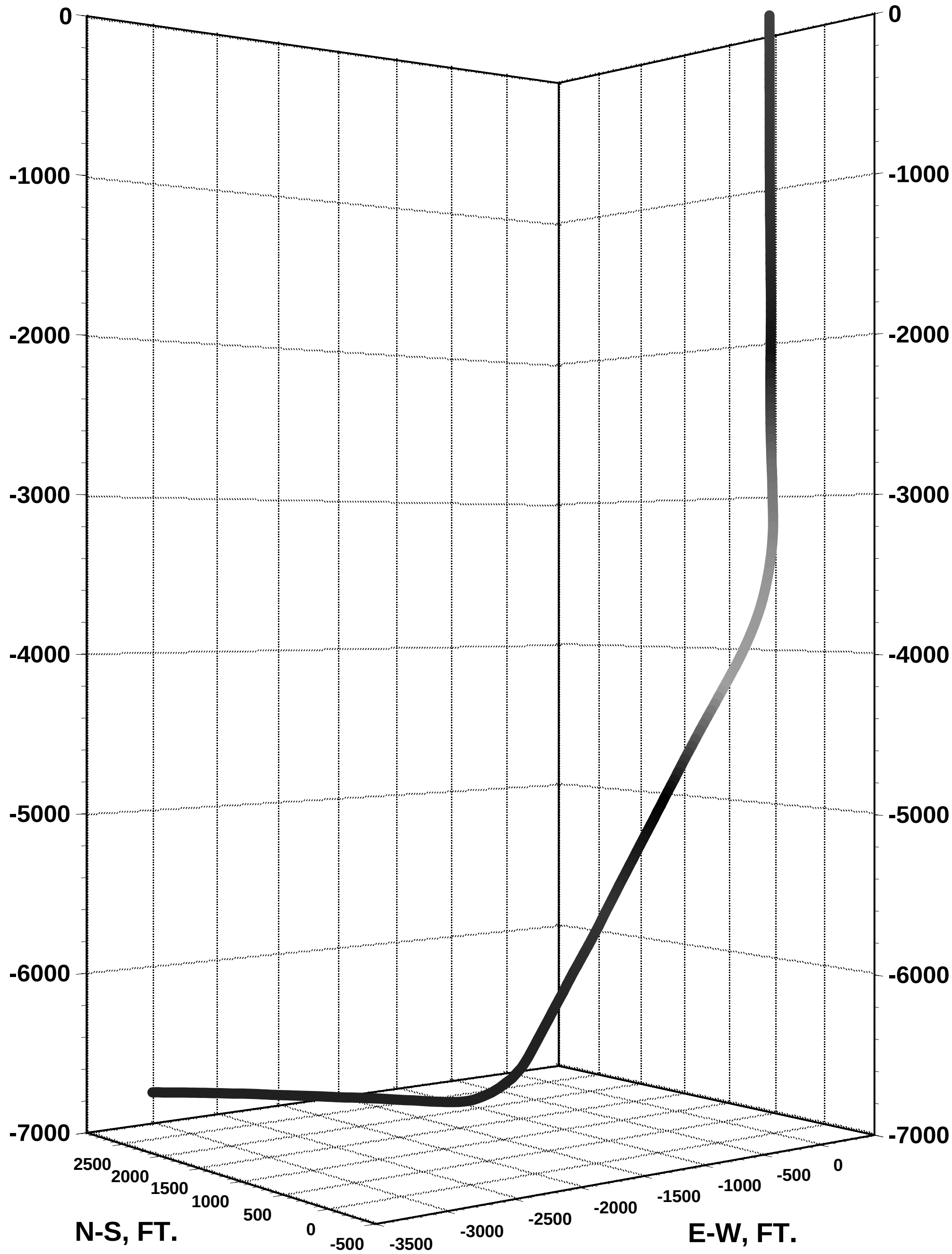


Fig. 31. NDP Well #33 final well path.

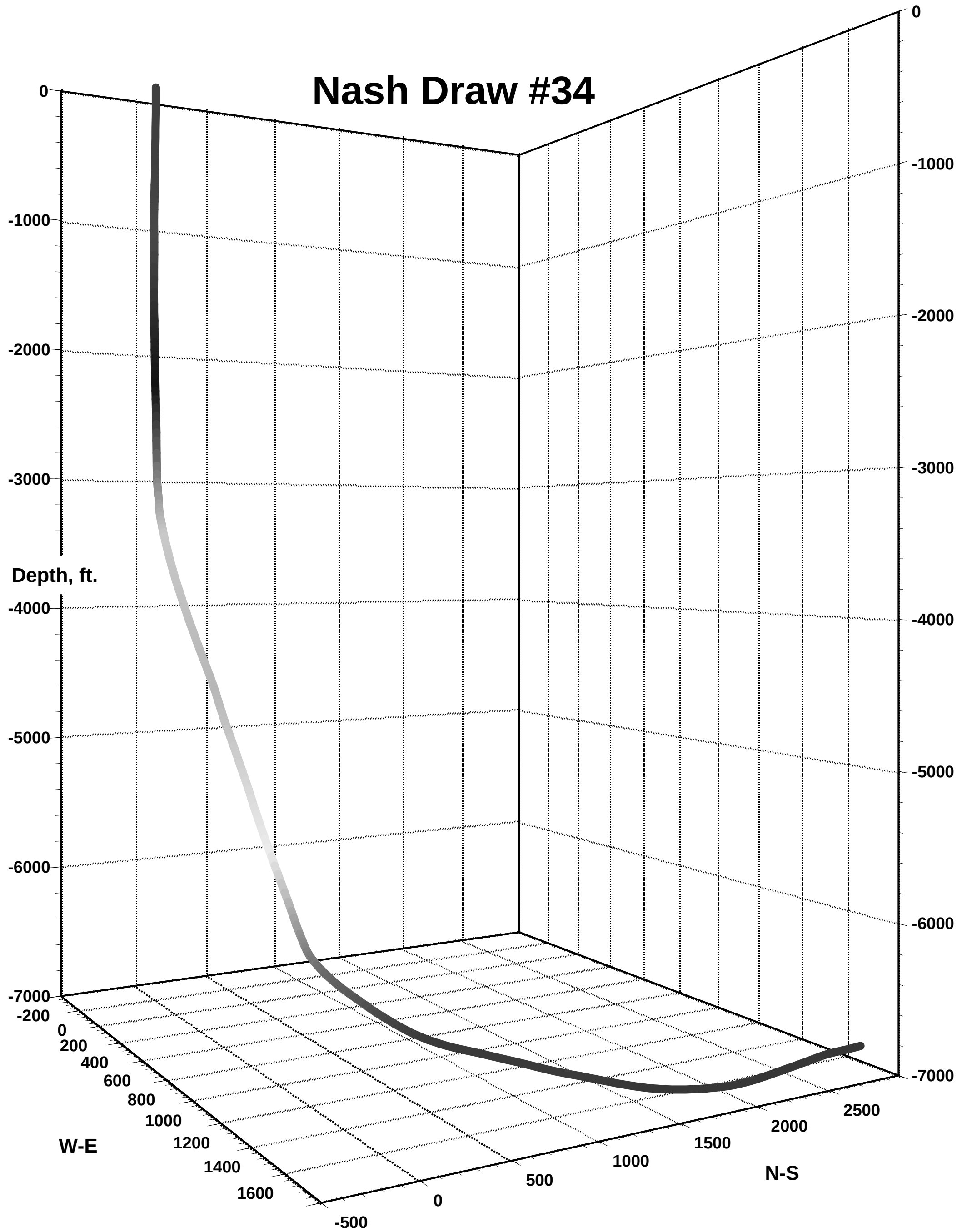


Fig. 32. NDP Well #34 final well path.

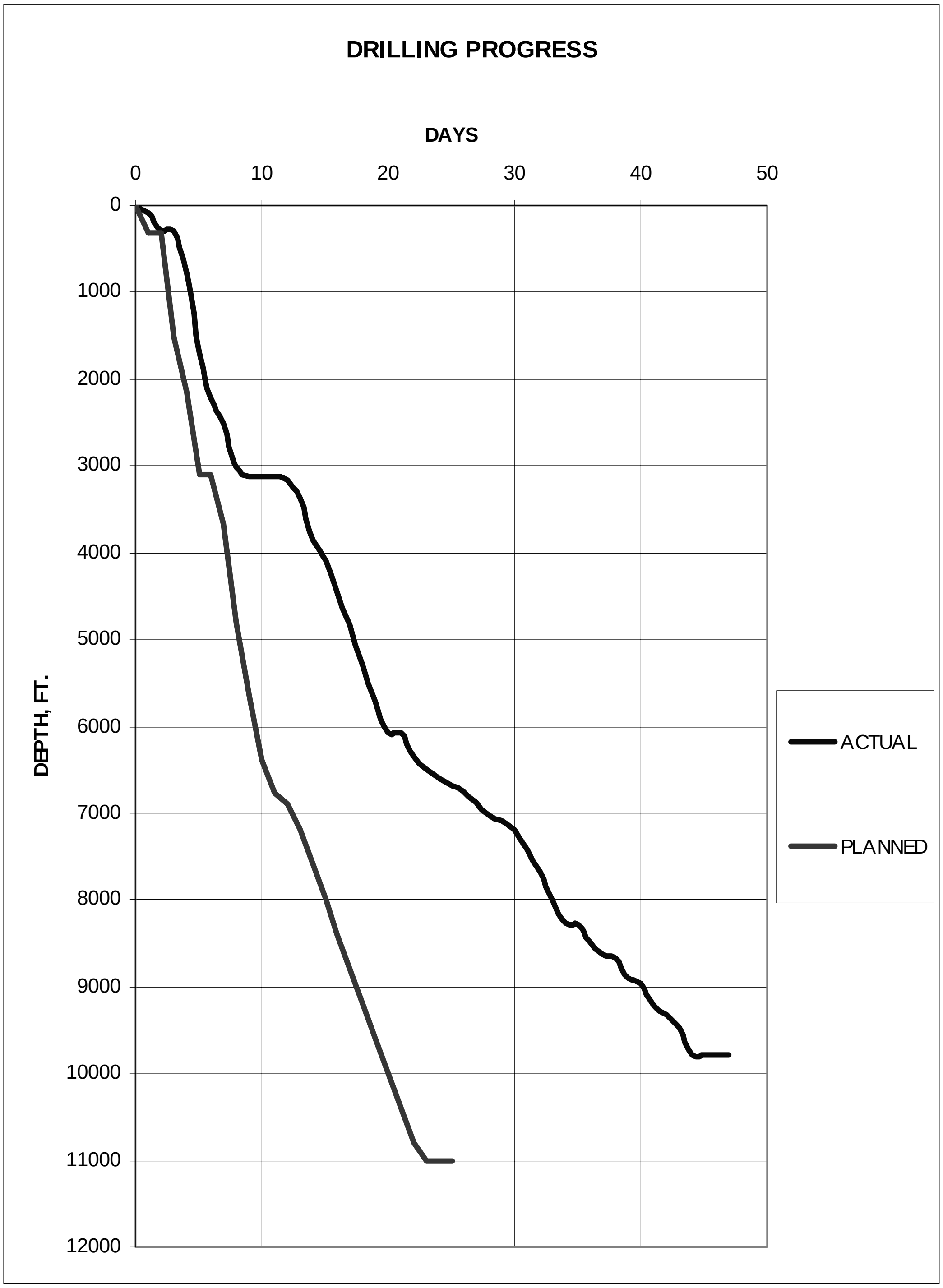


Fig. 33. NDP Well #36 drilling time.

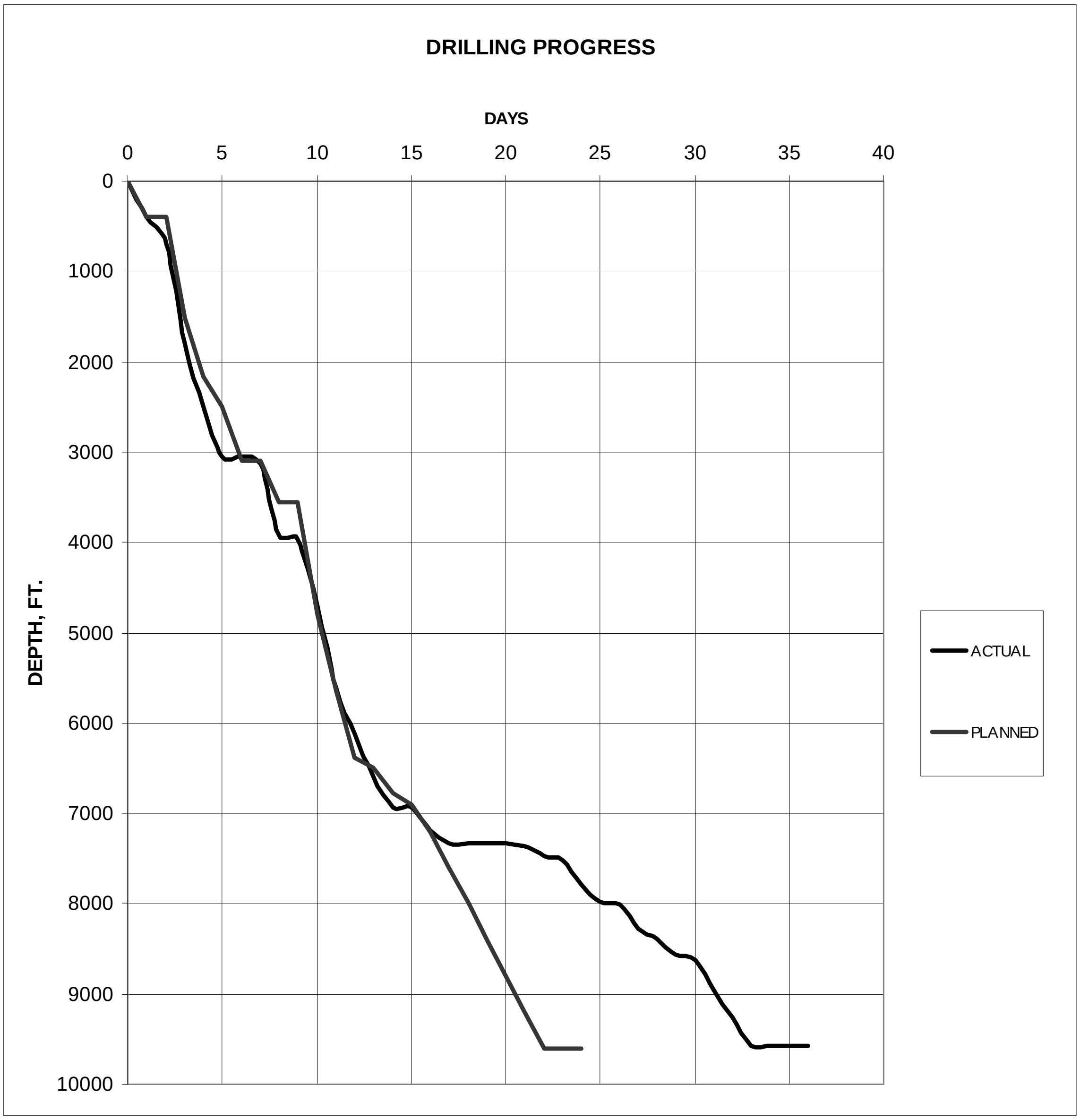


Fig. 34. NDP Well #33 drilling time.

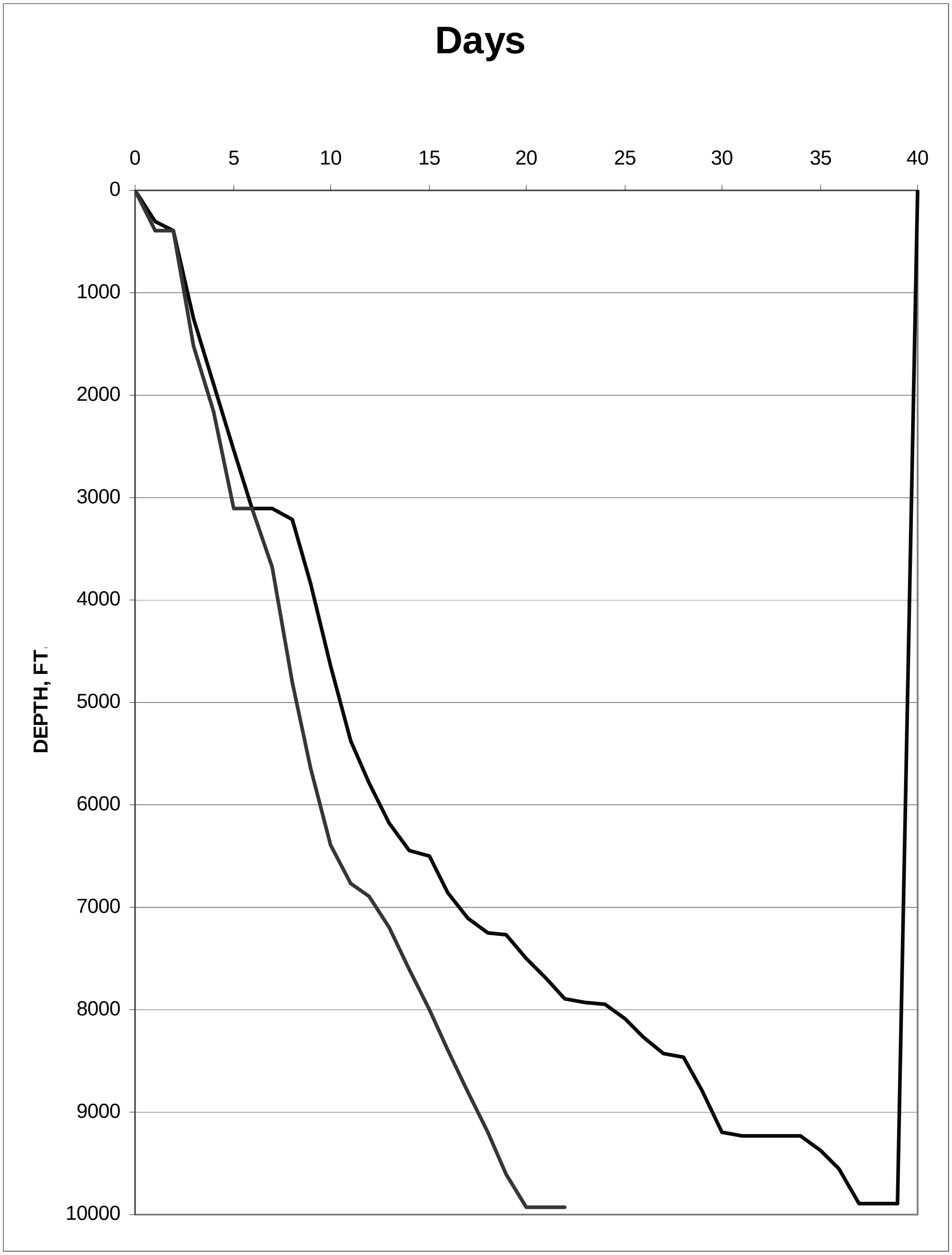


Fig. 35. NDP Well # 34 drilling time.

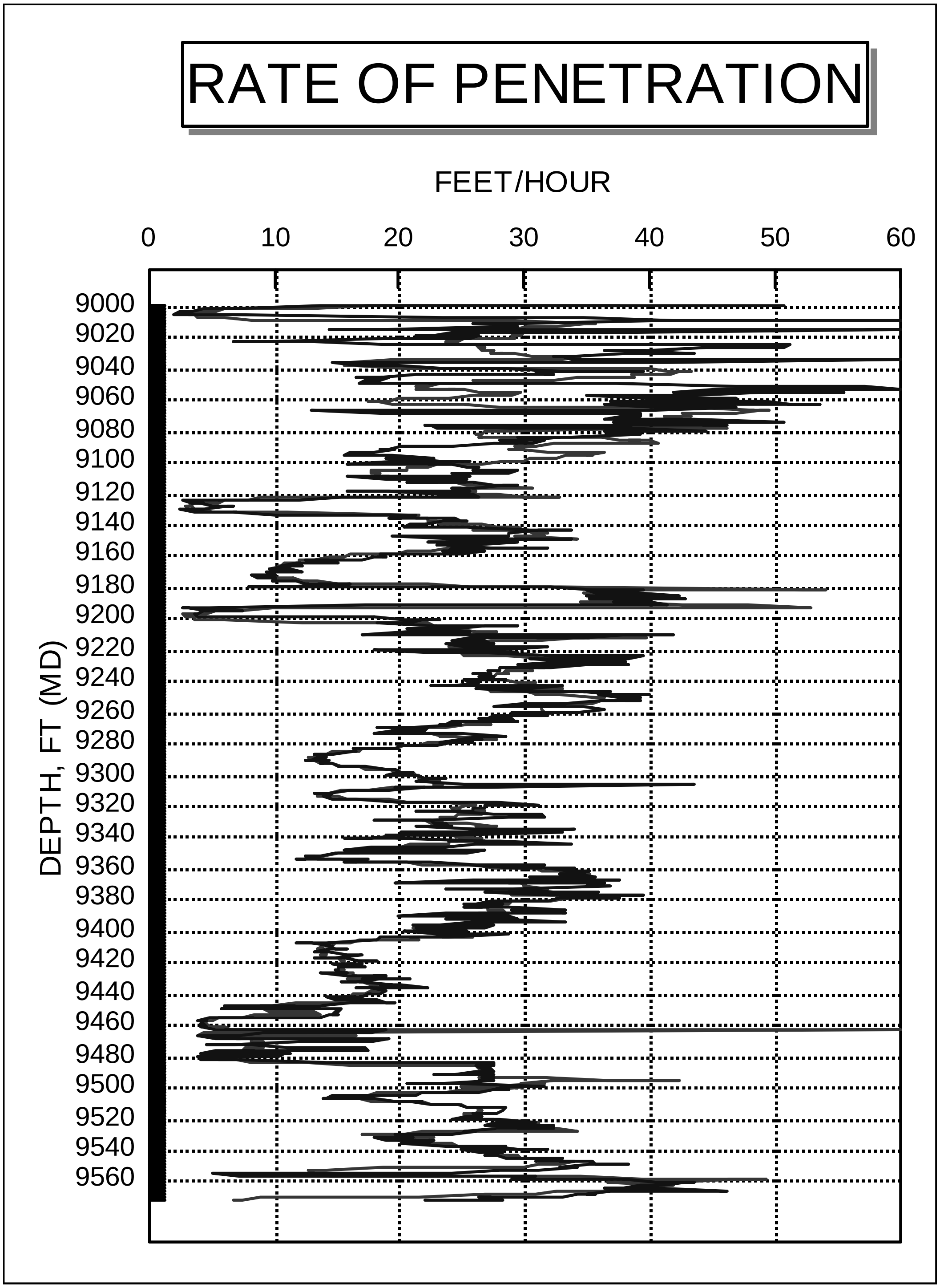


Fig. 36. Slide vs. rotary drilling, rate of penetration.

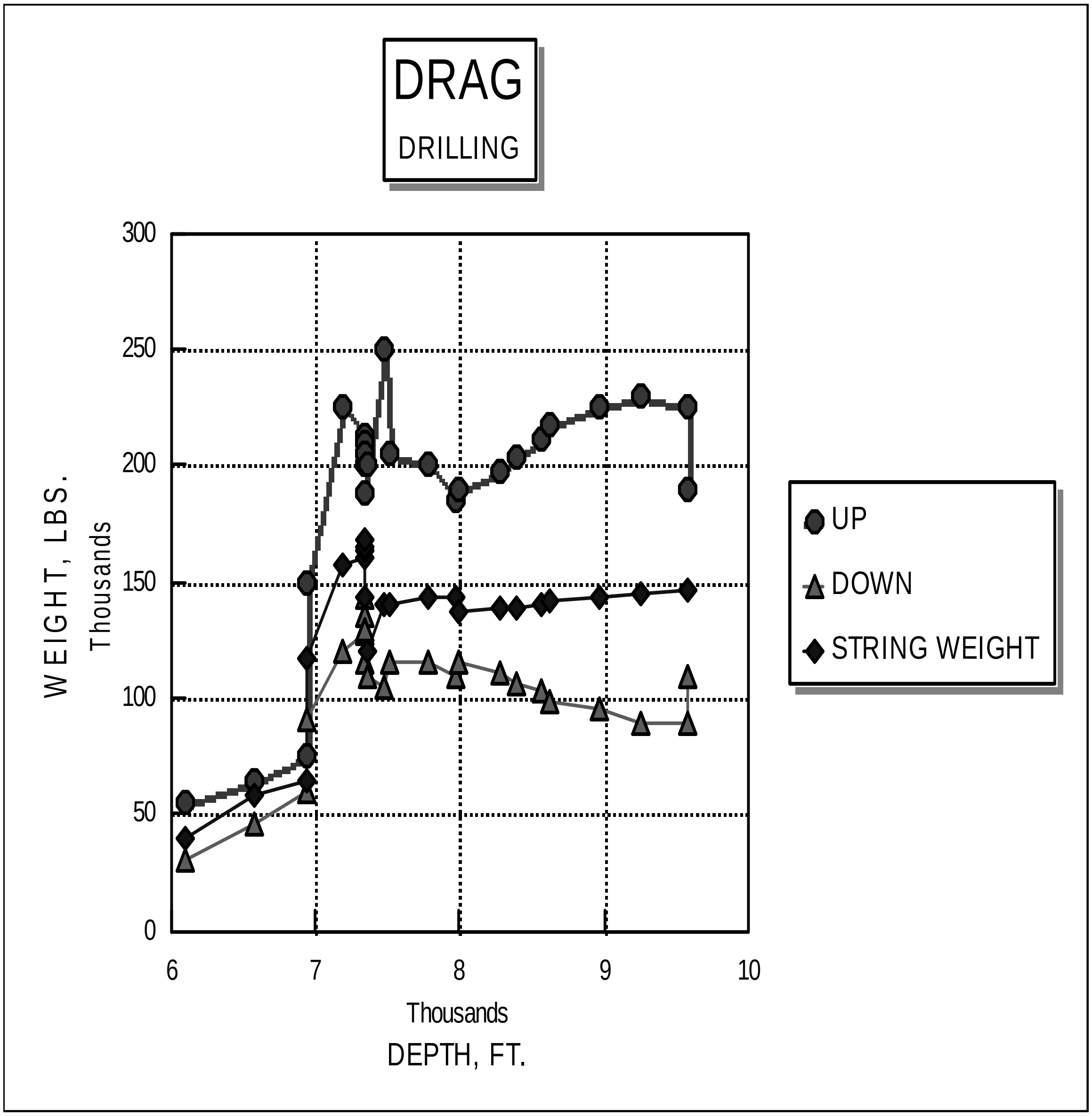


Fig. 37. Drag while drilling.

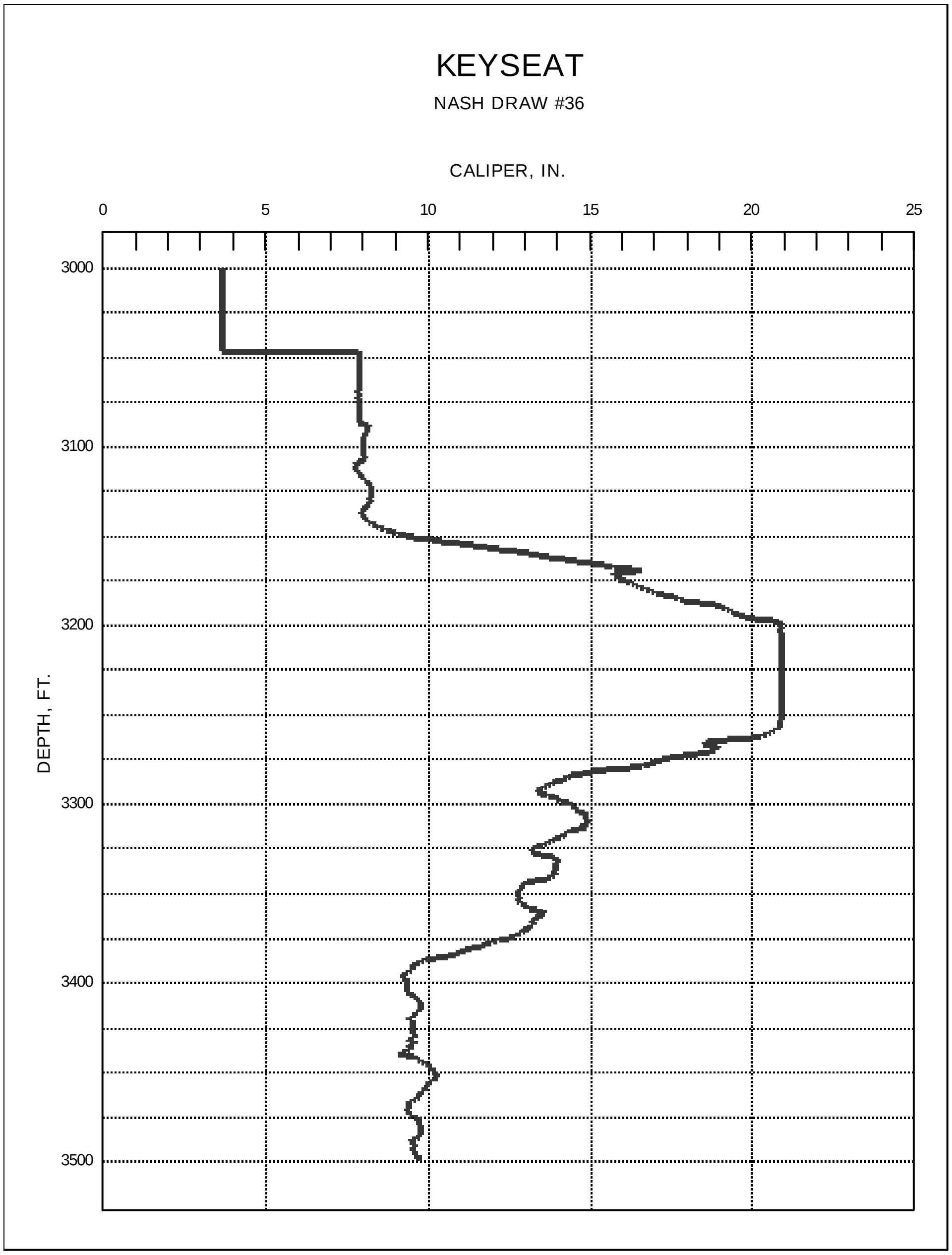


Fig. 38. NDP Well #36 keyseat.

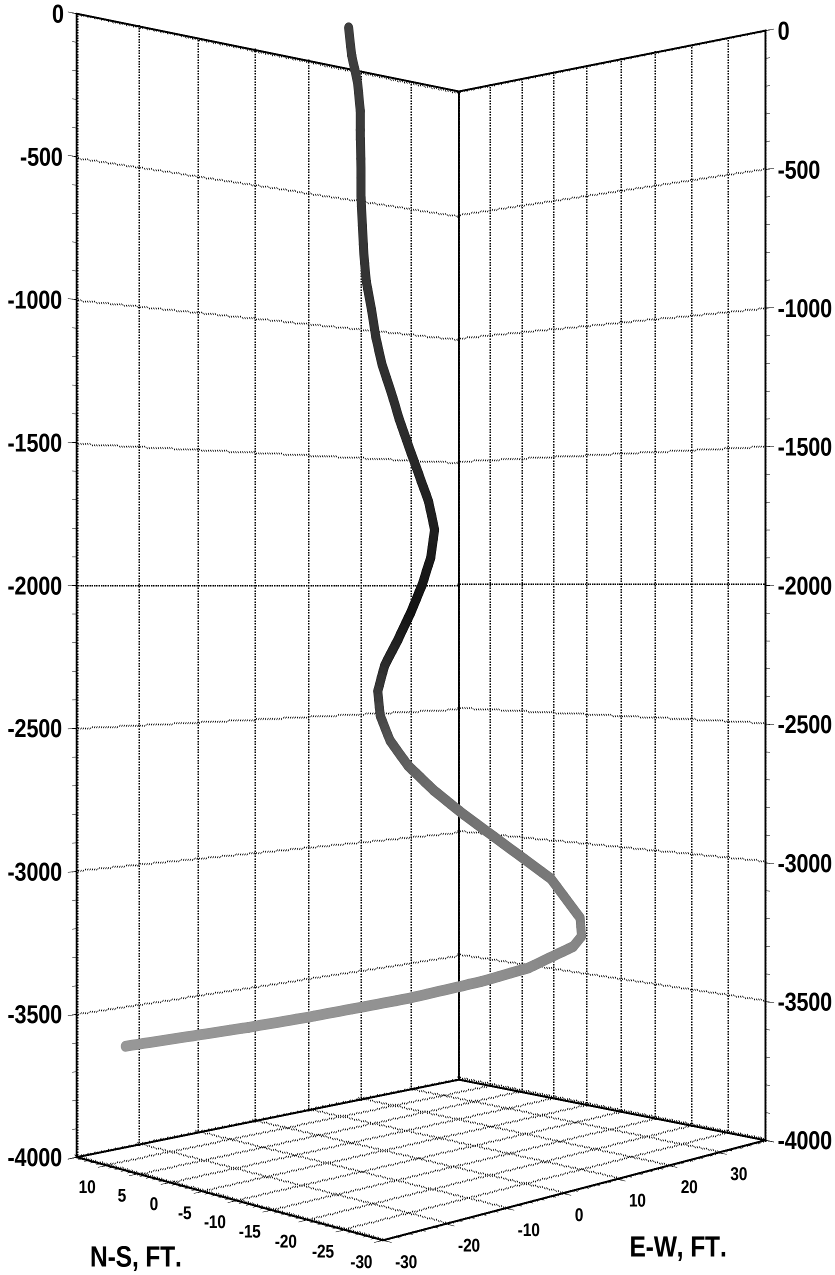
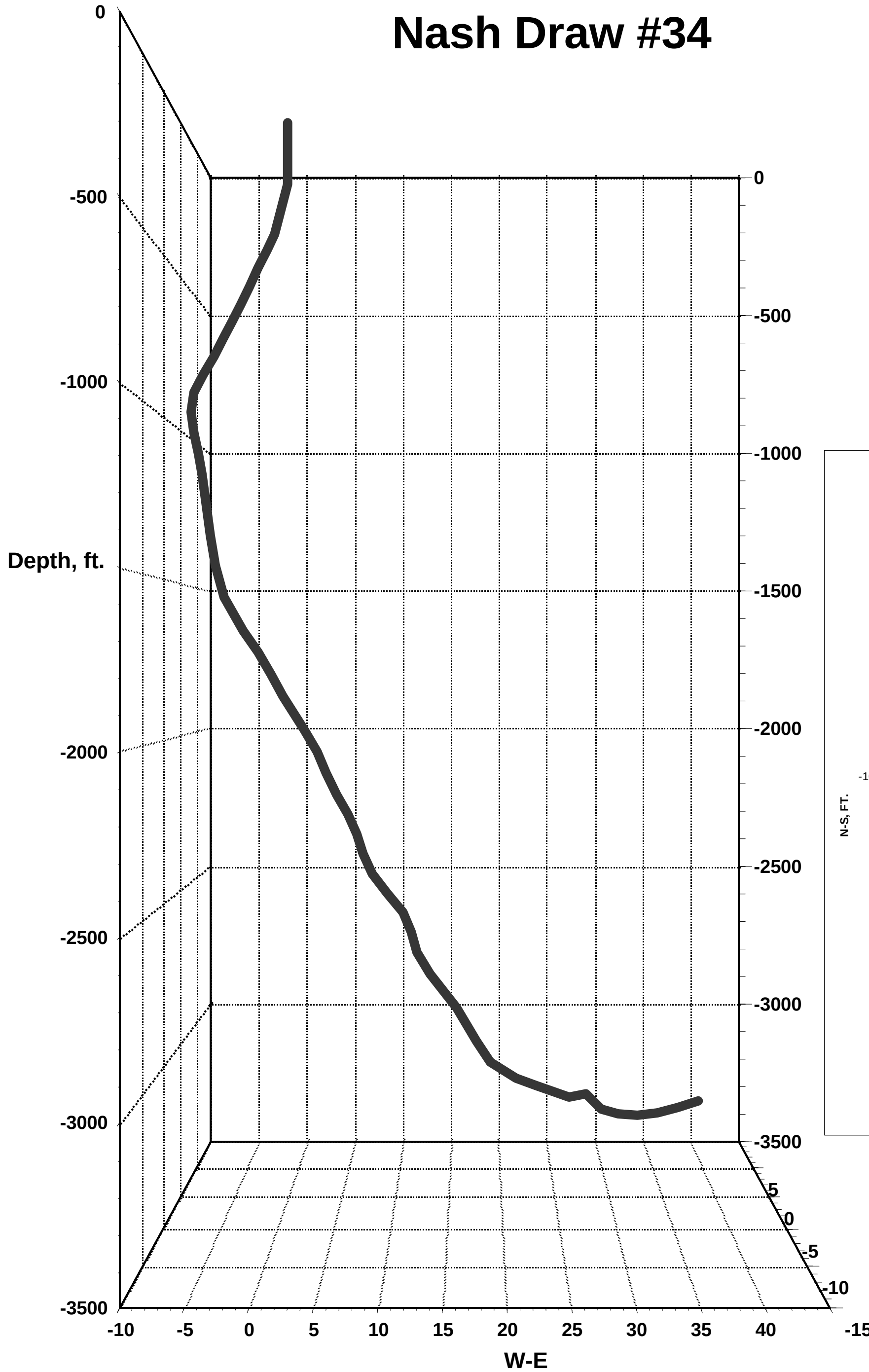


Fig. 39. NDP Well #33 deviation survey.



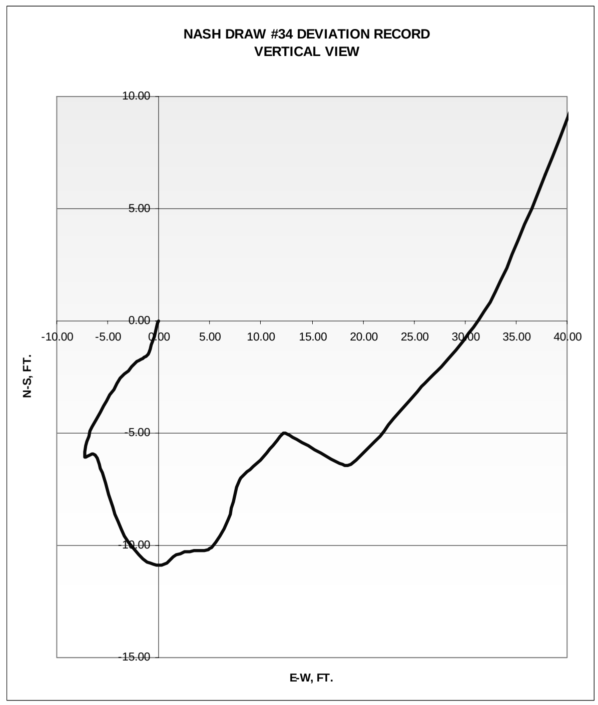


Fig. 40. NDP Well #34 keyseat.

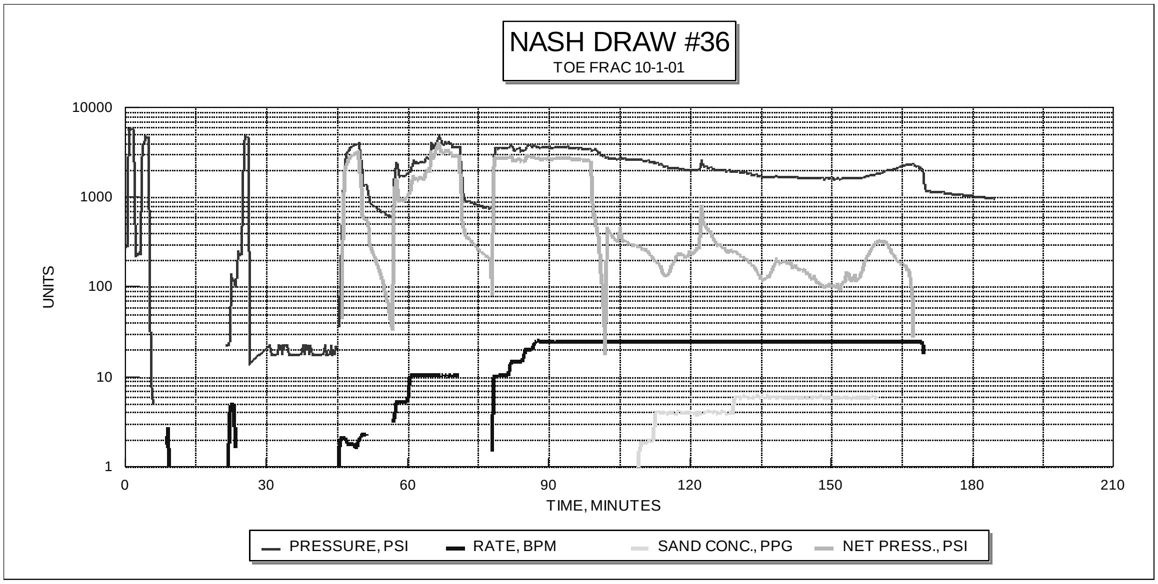


Fig. 41. NDP Well #36 toe zone #1 frac.

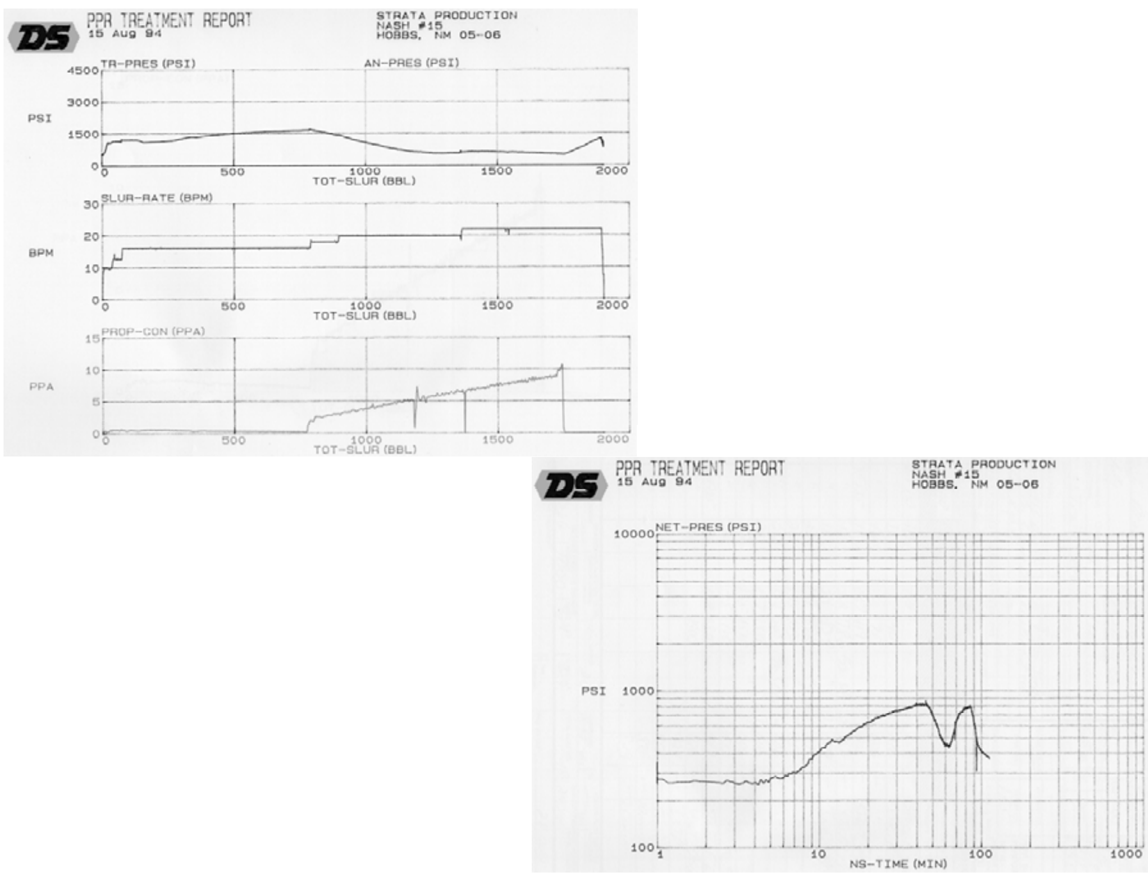


Fig. 42. Typical treating pressures on vertical well.

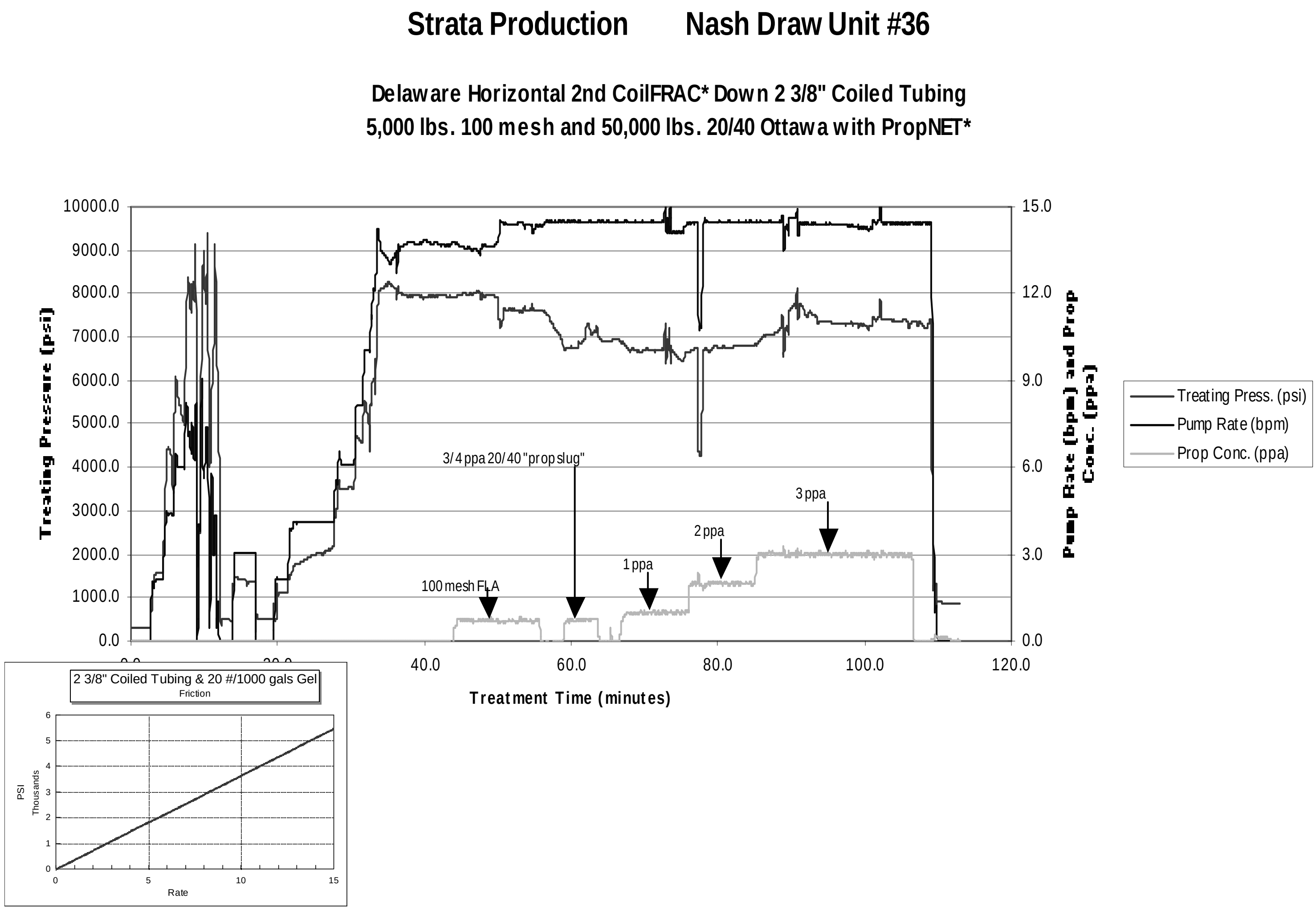


Fig. 43. NDP Well #36 zone #3 frac.

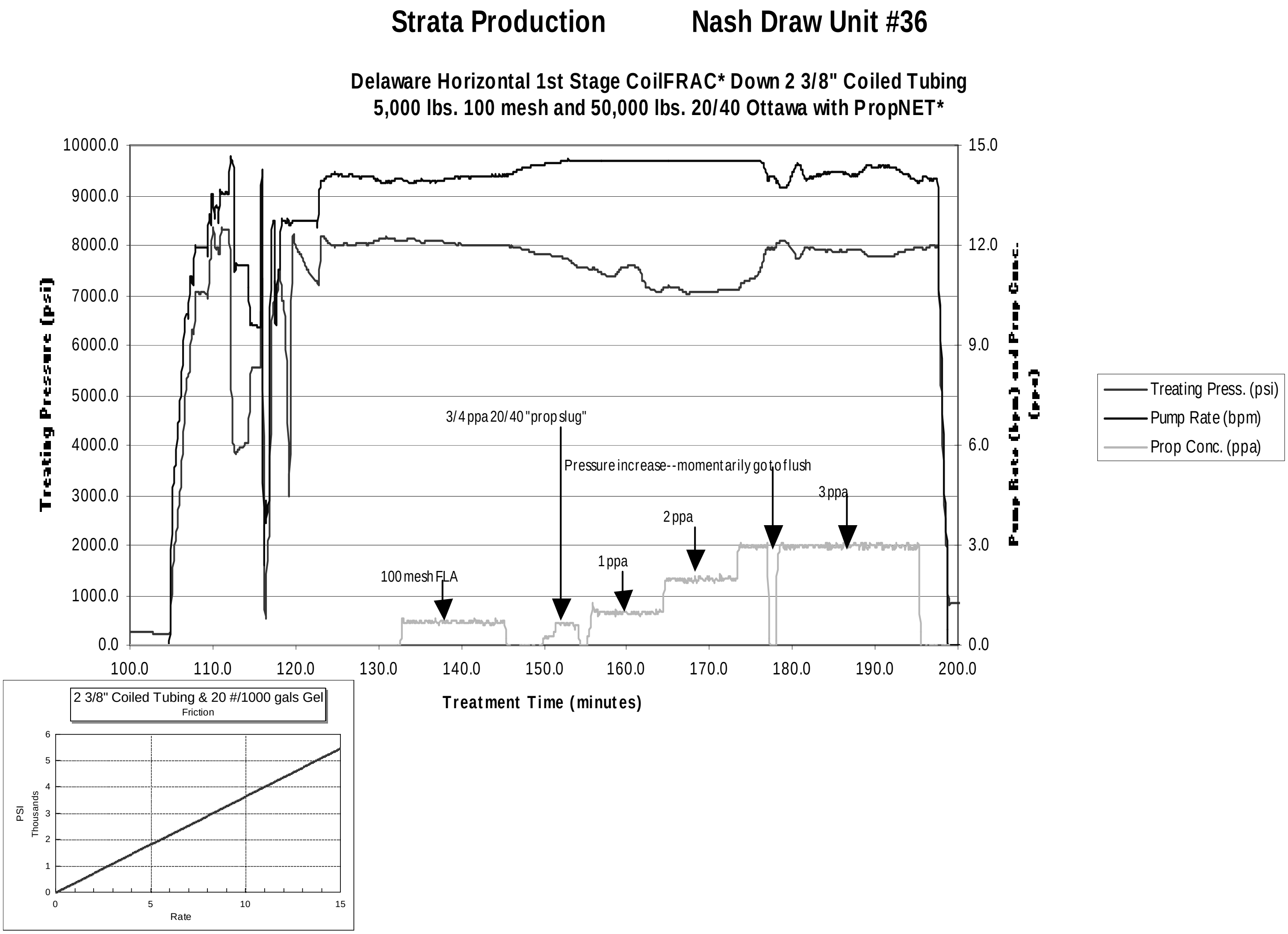


Fig. 44. NDP Well #36 zone #2 frac.

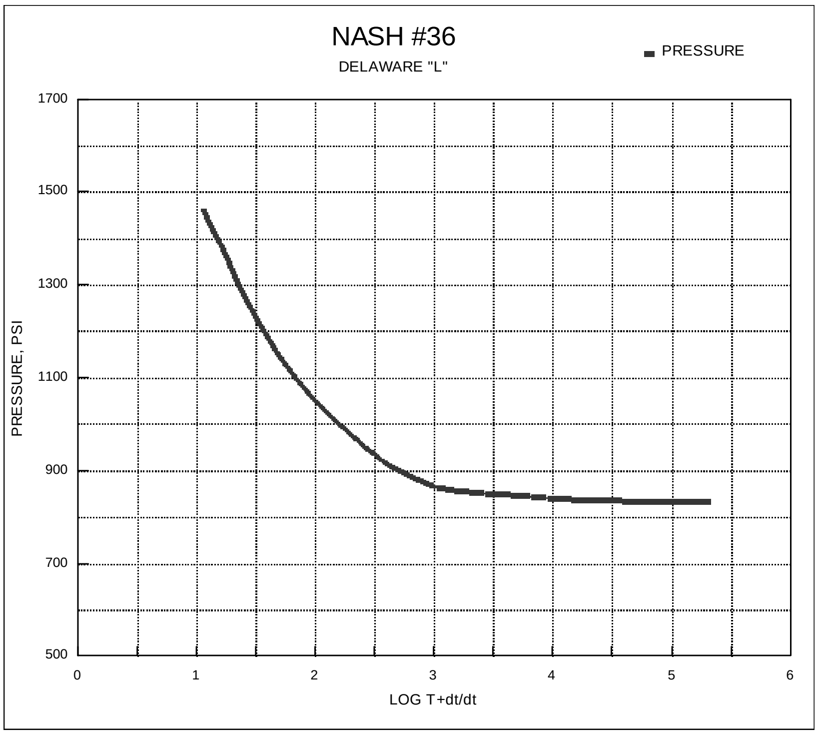


Fig. 45. NDP Well #36 BHP test.

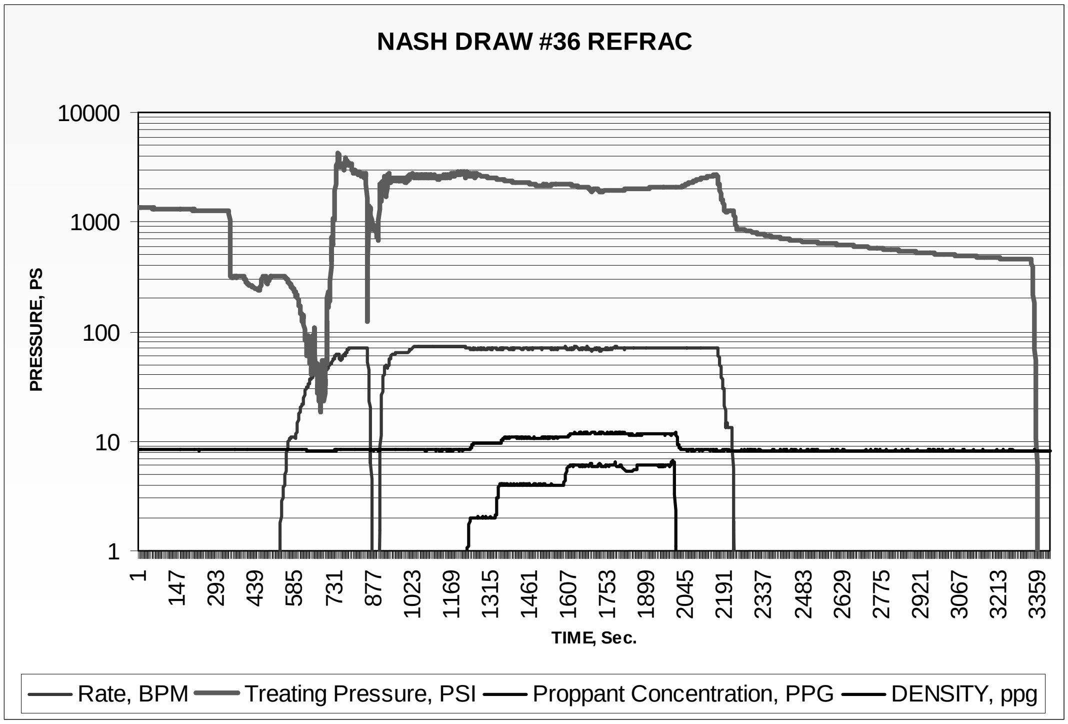


Fig. 46. NDP Well #36 refrac.

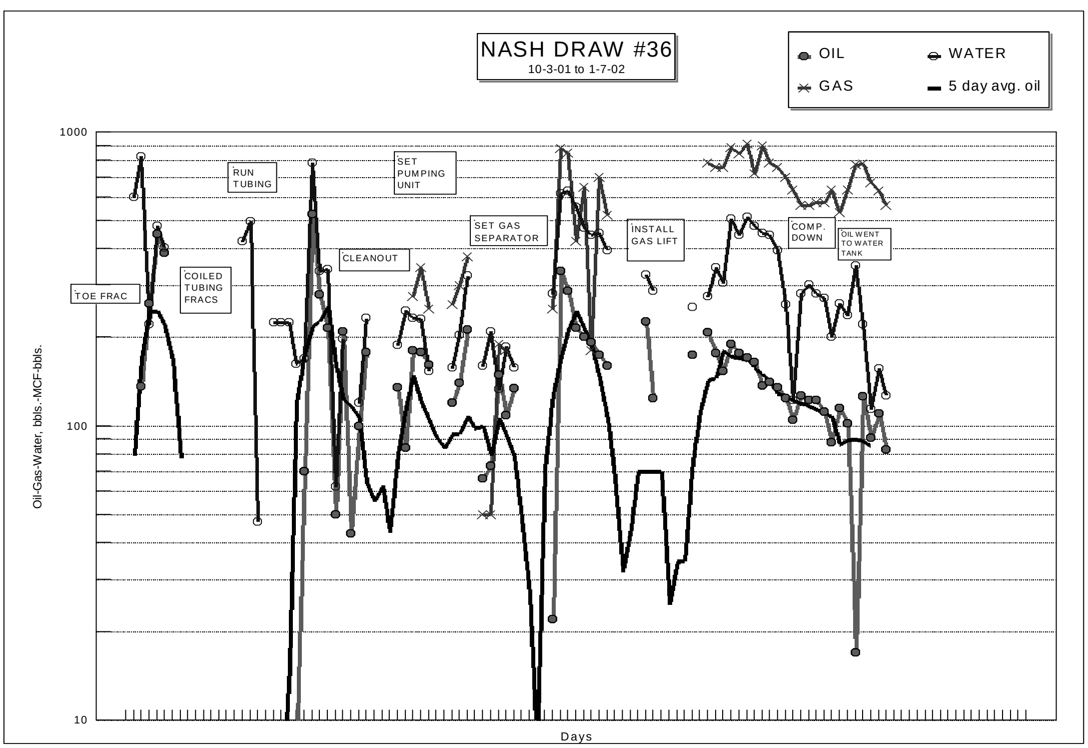


Fig. 47. NDP Well #36 daily production tests.

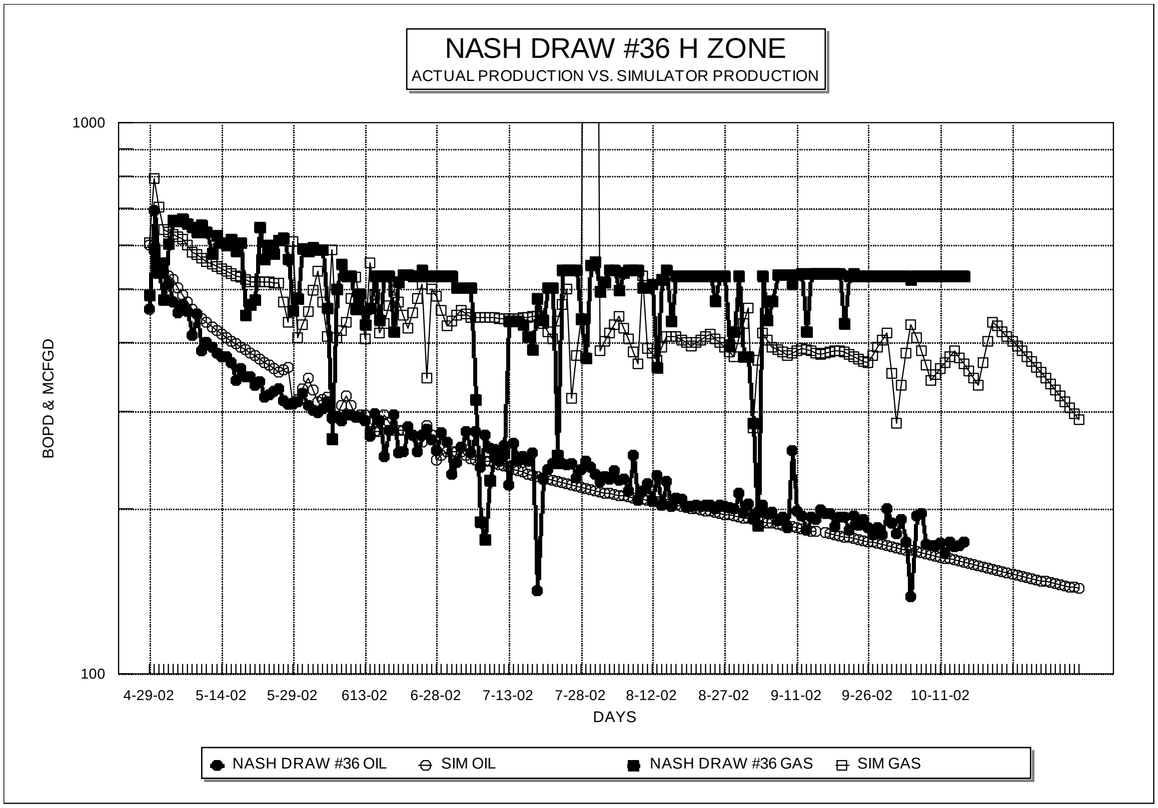


Fig. 48. NDP Well #36 "H-2" zone production.

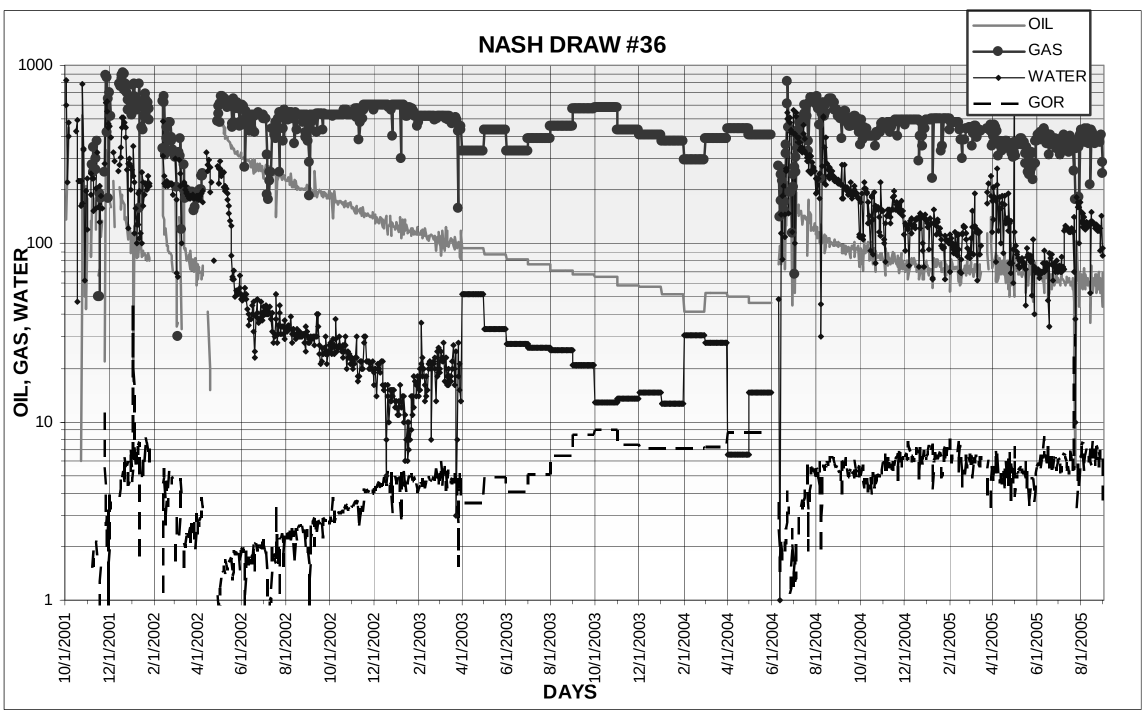


Fig. 49. NDP Well #36 production through September 1, 2005.

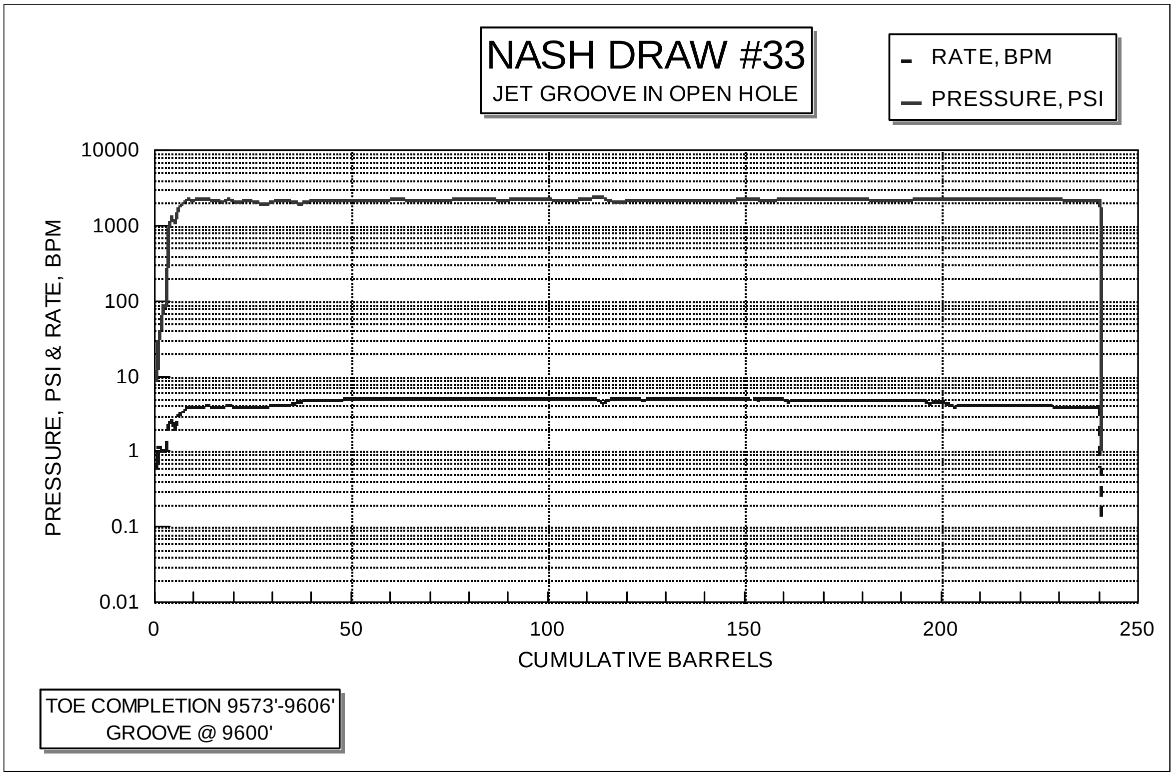


Fig. 50. NDP Well #33 jet groove in open hole.

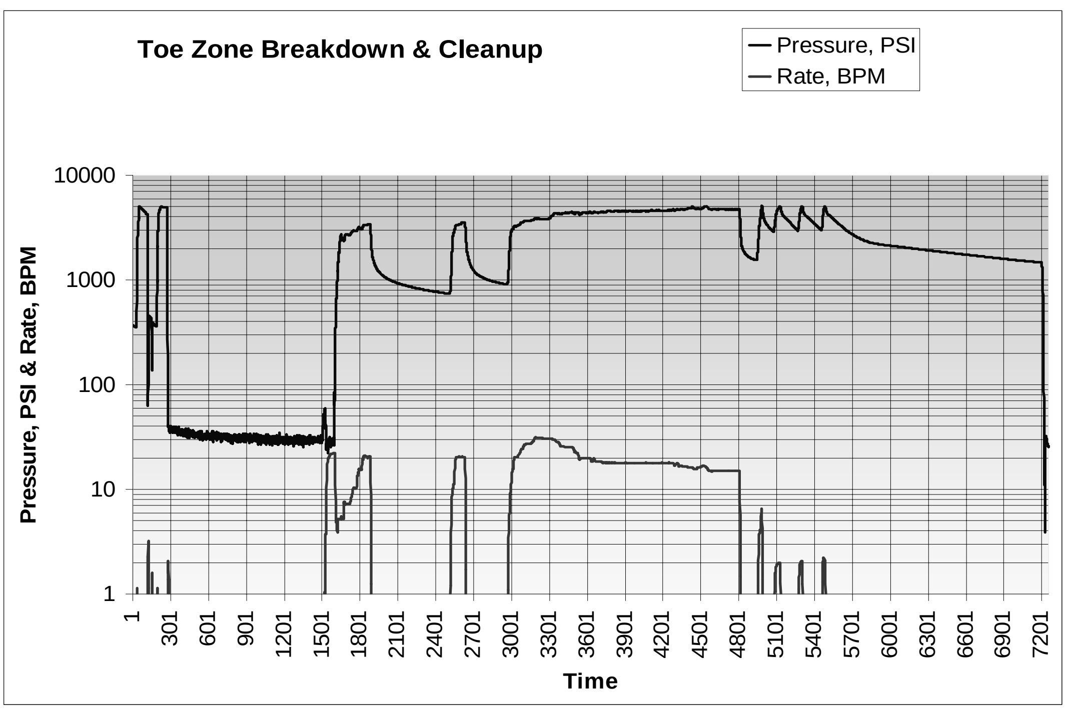


Fig. 51. NDP Well #33 frac of toe zone.

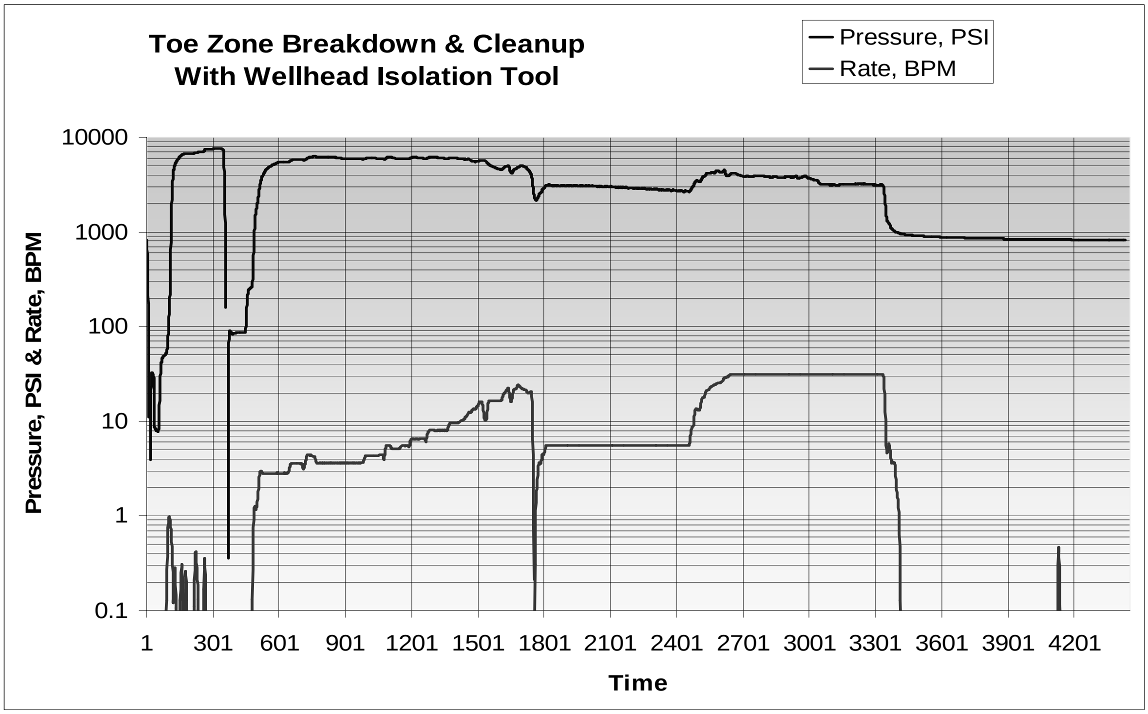


Fig. 52. NDP Well #33. Zone breakdown with wellhead isolation.

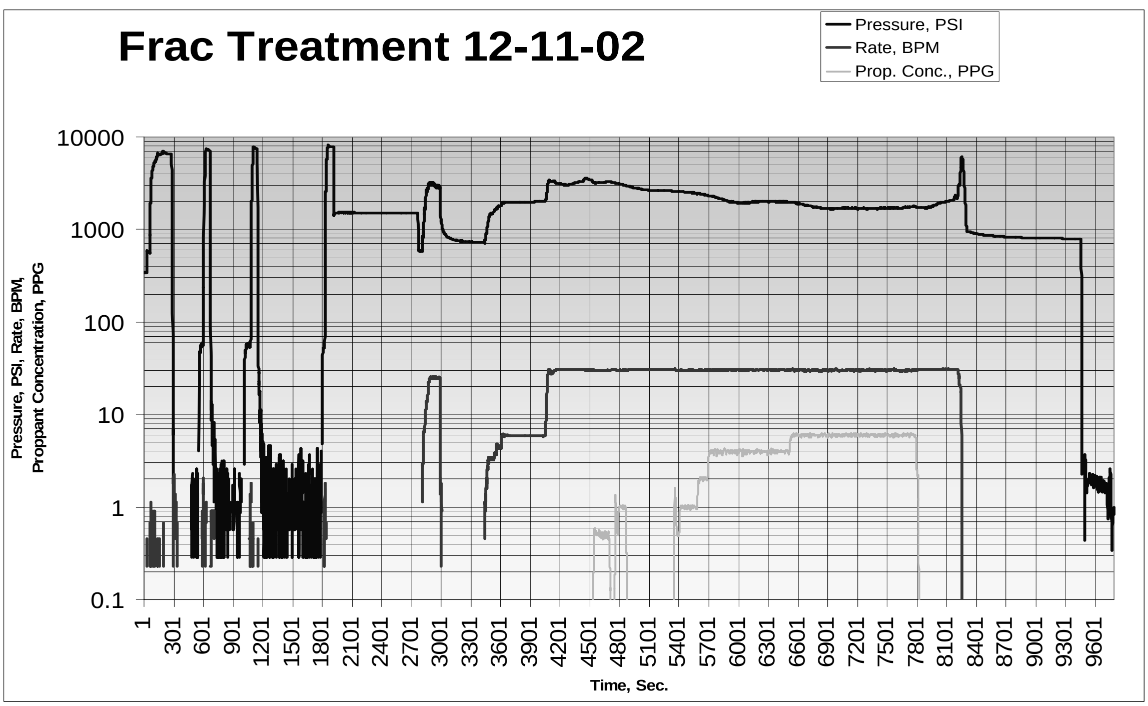


Fig. 53. NDP Well #33 frac treatment.

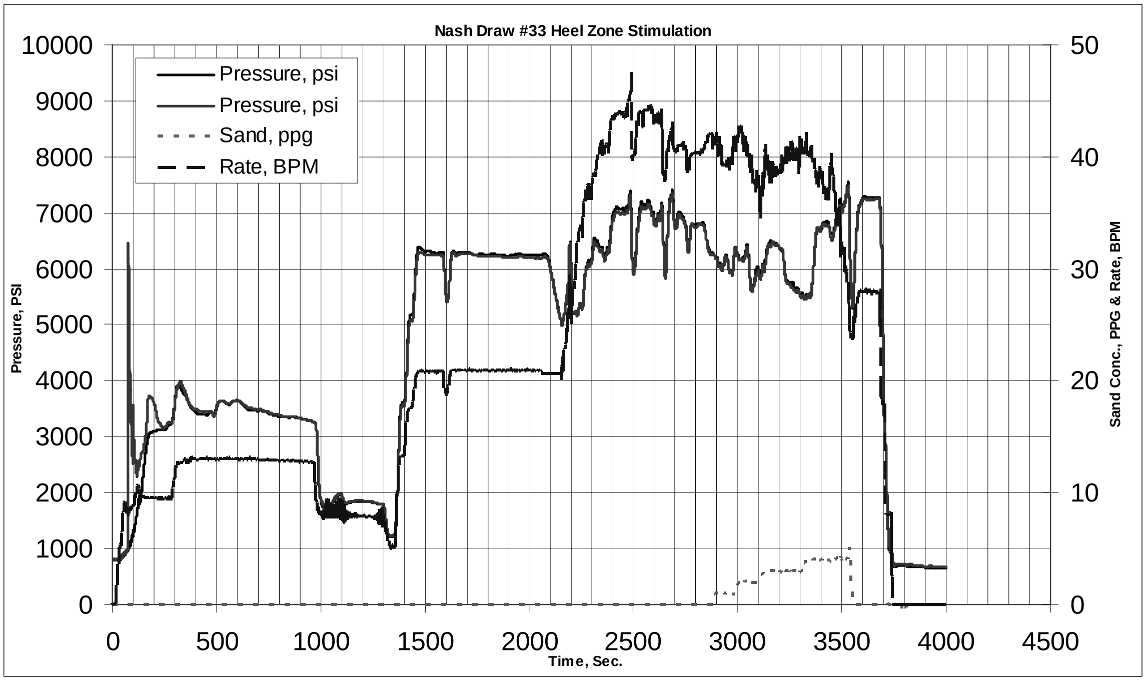


Fig. 54. NDP Well #33 frac of heel zone.

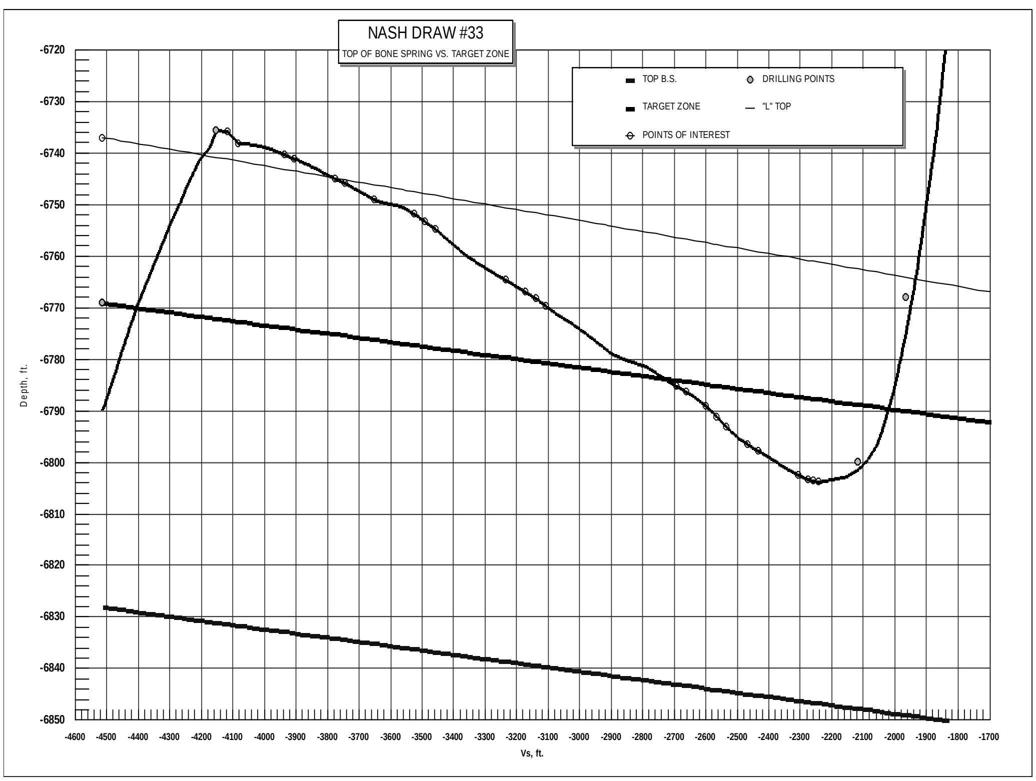


Fig. 55. NDP Well #33 deepening.

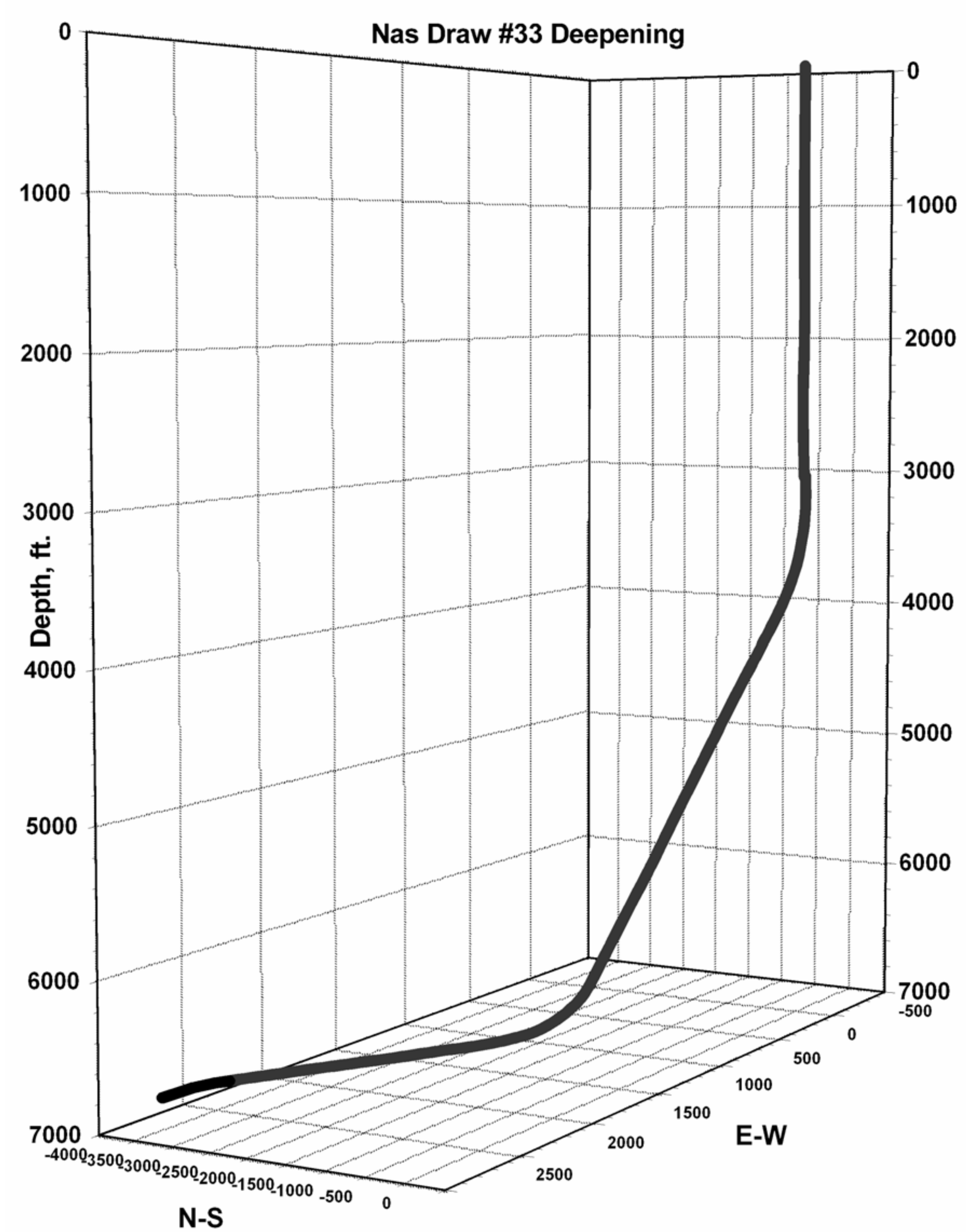


Fig. 56. NDP Well #33 open hole lengthened.

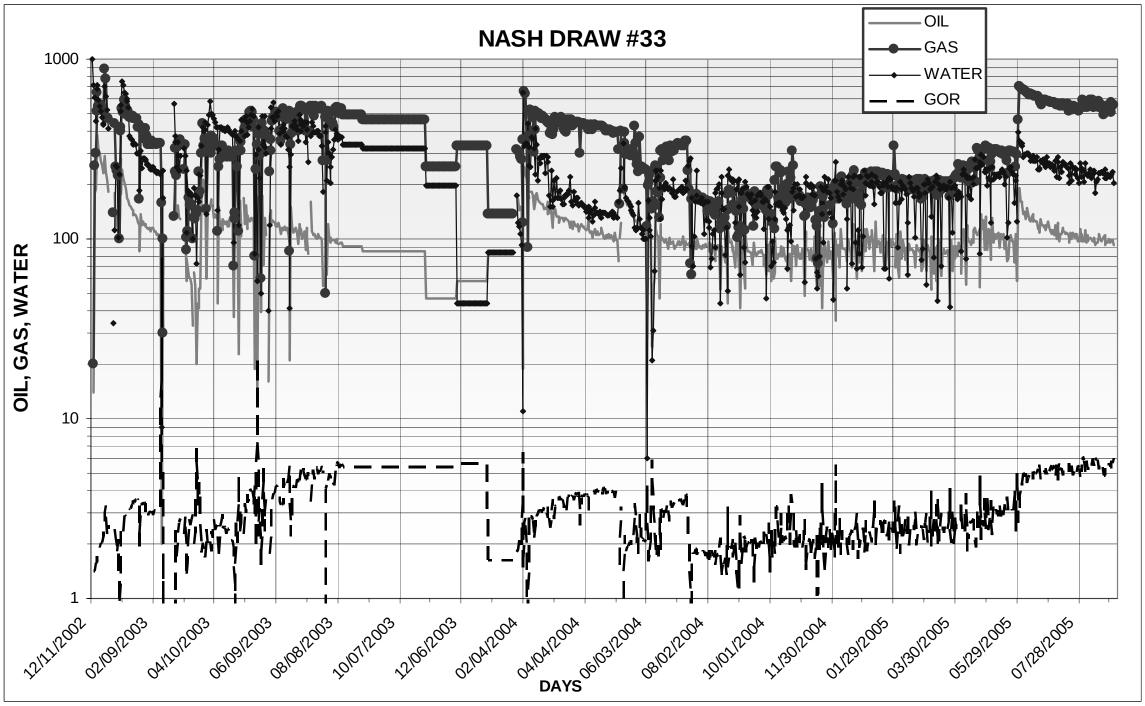


Fig. 57. NDP Well #33 production through September 1, 2005.

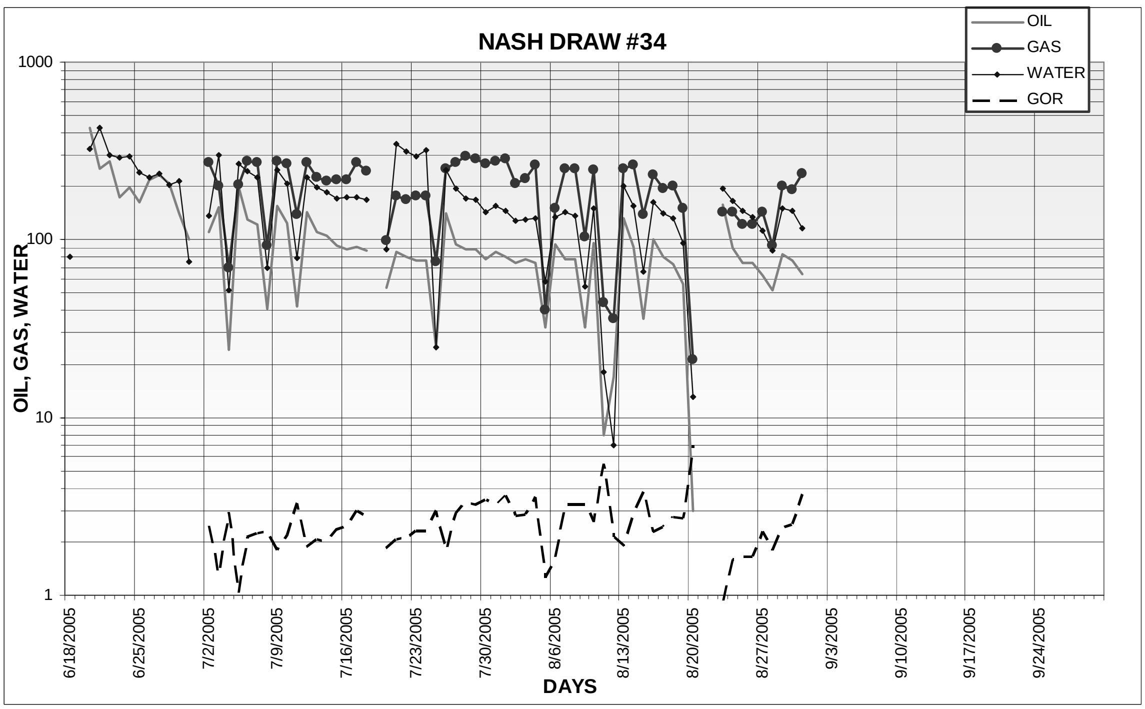


Fig. 58. NDP Well #34 production through September 1, 2005.

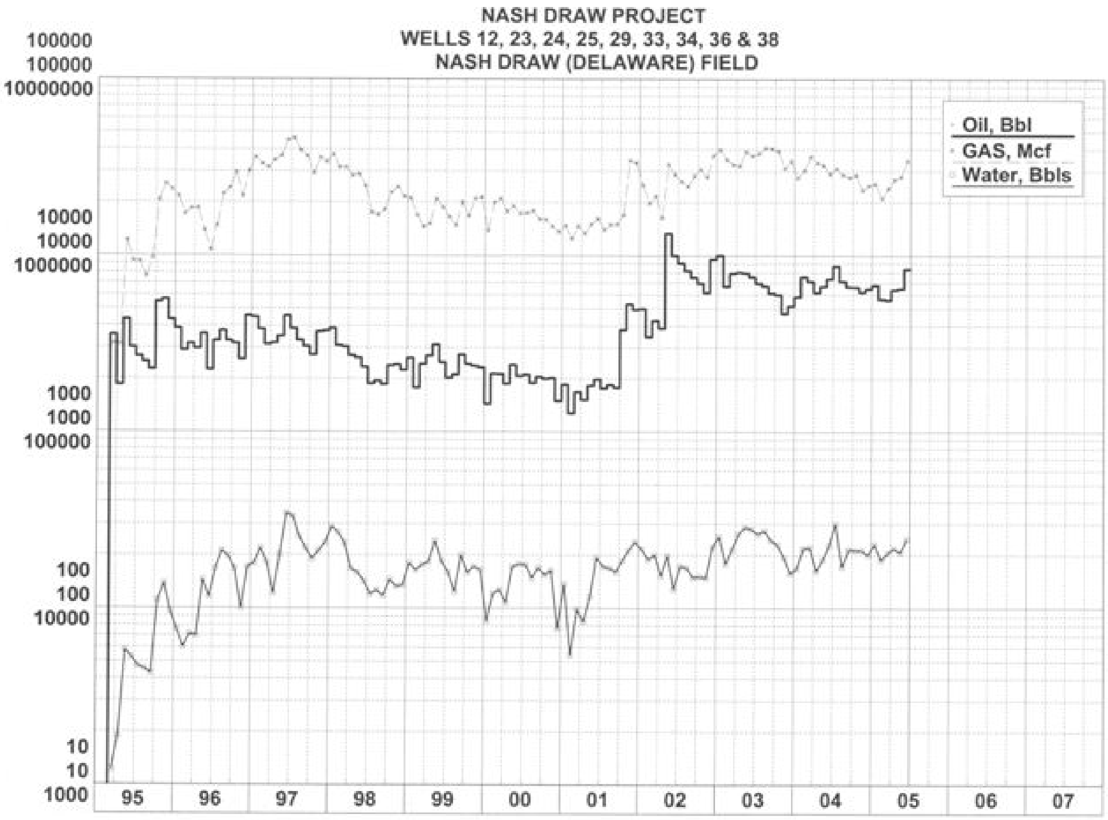


Fig. 59. Cumulative production of NDP DOE project wells through July 1, 2005