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PRRC 02-04

QUARTERLY TECHNICAL PROGRESS REPORT
(25th Quarter)

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

DOE Cooperative Agreement No. DE-FC-95BC14941

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Date of Report:	January 25, 2002
Award Date:	September 25, 1995
Anticipated Completion Date:	September 24, 1998 - Budget Period I
	September 25, 2001 - Budget Period II
Award Amount for Current Fiscal Year:	$2,017,435
Award Amount for Budget Period II:	$5,013,760
Name of Project Manager:	Mark B. Murphy
Contracting Officer's Representative:	Dan Ferguson
Reporting Period:	September 30, 2001–December 31, 2001

US/DOE Patent Clearance is not required prior to the publication of this document.

OBJECTIVE

The overall objective of this project is to demonstrate that a development program based on advanced reservoir management methods can significantly improve oil recovery at the Nash Draw Pool (NDP). The plan includes developing a control area using standard reservoir management techniques and comparing its performance to an area developed using advanced reservoir management methods. Specific goals are (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 oil and gas producers in the Permian Basin and elsewhere throughout the U.S. oil and gas industry.

SUMMARY OF TECHNICAL PROGRESS

This is the twenty-fifth quarterly progress report on the project. Results obtained to date are summarized.

Geology and Engineering

The production database was updated through October 2001. 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.

Nash Draw #36 Completion

The completion of the Nash Draw #36 was started in October 2001 and production testing and analysis is continuing. Three intervals at the end of the well were initially completed (Fig. 1). The intervals are 9786-9805 ft, 9464-9470 ft and 9123-9129 ft.

Toe Completion:

1. R.I.H. with coiled tubing to T.D. (9805 ft) and spot 500 gal of 7 1/2% NEFE acid across the open hole. P.O.H. to 9300 ft and reverse-circulate the hole. P.O.H. with coiled tubing unit. Breakdown, establish a rate into the formation of 10 BPM and pump a total of 50 bbl. Note breakdown pressure, ISIP, 5 min, 10 min and 15 min shut-in pressures. Flow back to bleed off pressure.

2. Frac "L" zone with 71,000 gal 35 #/1000 gal cross-linked gelled KCL water carrying 216,000 lbs of 16/30 Jordan sand. Treatment to include J501-PROPNET proppant stabilizer in the last 60,000 lbs of sand. Rate: 25 BPM with an anticipated surface treating pressure of 2000 psi, maximum pressure 3500 psi. Flush with casing volume, approximate displacement volume is 229bbls, do not over-flush.

3. R.I.H. with coiled tubing and clean out wellbore.

Mohave Completions:

1. T.I.H. with perforating guns on 2.375-in. coiled tubing, perforate 9464–9470 ft, 6 ft, with 6 JSPF, 37 shots, using pressure-activated firing head. P.O.H.
2. T.I.H. with perforating guns on 2.375-in. coiled tubing, perforate 9123–9129 ft, 6 ft, 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 ft, break down and acidize with 1000 gal 7.5% NEFE acid.
4. Frac with 40,000 gal 20 #/1000 gal linear gel carrying 50,000 lbs of 20/40 Jordan sand at 14 BPM.
5. Move Mojave Tool to straddle 9123–9129 ft, break down and acidize with 1000 gal 7.5% NEFE acid.
6. Frac with 40,000 gal 20 #/1000 gal linear gel carrying 50,000 lbs 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 1.25-in. coiled tubing and clean out the horizontal section to T.D.
9. Put well on production.

The completion procedure was followed as written, with a few modifications due to unforeseen problems. The main problems were:

1. The rubber cups on the Mohave frac tool are 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 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 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.
5. Production declined rapidly and sources of damage are being investigated.

The Mohave frac tool is an opposed cup tool with a variable mandrel length that can be adjusted to straddle the perforated interval to be treated. Other features of the tool include a by-pass and a dump valve. Because the cups are in contact with the casing during running of the tool, the cups are subject to wear and damage. To minimize damage, fluid was circulated around the tool at a slow rate (1 to 2 BPM) to keep the upper cup collapsed. One cup was damaged when it “hung” in the D.V. tool and another set of cups were damaged when they were set in perforations while trying to move the tool to the second set of perforations.

All three frac treatments had some degree of tortuosity. The toe frac (Fig. 2) was expected to treat at approximately 1800 psi. The initial treating pressure was 4000 psi at 2 to 10 BPM. Two shut-ins were observed with ISIP pressures of 900 psi. After starting the treatment and establishing a rate of 25 BPM the treating pressure was approximately 3800 psi. This was approximately 2000 psi above the anticipated pressure. At 125 min into the treatment, the 4 ppg sand concentration was on the formation and a momentary 500 psi increase in treating pressure was observed. By the end of the treatment, after pumping 222,000 lbs of 16/30 sand, the treating pressure decreased to 2400 psi and the ISIP was 1200 psi.

The first Mohave frac treatment (Fig. 3) was anticipated to treat at 6000 psi at 14 BPM. The initial treating pressure was 8150 psi at 14 BPM, a 2000 psi increase over the anticipated pressure. Unlike the toe frac, the ending treating pressure did not decline and was 8000 psi at 14 BPM with an ISIP of 850 psi.

The second Mohave frac treatment (Fig. 4) was anticipated to treat at 6000 psi at 14 BPM. The initial treating pressure was 8100 psi at 13.6 BPM, a 2000 psi increase over the anticipated pressure. Unlike the first Mohave frac, the ending treating pressure declined slightly to 7400 psi at 14.4 BPM with an ISIP of 900 psi.

The ISIPs were similar to vertical well shut-ins, but treating pressures were 2000 psi above normal vertical well treating pressures. With the ISIP pressures of 900 psi the frac gradient is estimated to be 0.57 psi/ft. with the resulting closure pressure of 3860 psi. This correlates closely to frac gradients and closure pressures observed in other vertical wells in the field. The additional treating pressure is 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 from vertical. Whichever mechanism or combination of mechanisms contributes to the higher treating pressures also causes narrow fracture widths, as evidenced by the pressure increases when sand concentrations were stepped up. Maximum sand concentrations were only 3 to 4 PPG on this well, with indications that higher concentrations would not tolerated. On the vertical wells in the field, maximum sand concentration are routinely run at 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.

Sand crushing and the resulting reduced permeability to the sand pack are one explanation of the production characteristics of this well. Initially, after the toe zone was completed flow rates were 50 to100 bbls of fluid per hour, with a 50% oil cut and gas at a rate of +/- 2 MMCFGD. Presently rates have declined to 300 BPD with a 40% oil cut and 600 MCFGD. Production has decreased by 2/3 which is a much steeper decline than expected. The #15 well produced from 100 to 200 BOPD for the first six months, from one completion.

A bottom-hole-pressure-buildup is planned for the end of January to determine damage, stimulation effectiveness, BHP and depletion. If the analysis indicates near wellbore damage and high BHP a restimulation treatment will be performed using a high strength proppant to repack the near wellbore area.

The results of this testing and final completion will be presented in the next Quarterly Report.

Two more workovers, to add additional pay zones, are planned for the Nash Draw #1 and #20 wells. The results of this work will be reported in the next Quarterly Report.

Technology Transfer

Disseminating technical information generated during the course of this project is a prime objective of the project. A summary of technology transfer activities during this quarter is outlined below.

Internet Homepage: The address of the Website for the Nash Draw project is: http://baervan.nmt.edu/REACT/Links/nash/strata.html. This site includes the annual reports and the final Phase I report, including graphics.

"A New Tool For Brushy Canyon Completion Decisions," was presented at the West Texas Geological Society Fall Symposium in Midland, Texas on October 25-26, 2001

"The Nash Draw #36 Completion," was presented at "The Coiled Tubing Symposium" held in Midland, Texas on December 12, 2001.

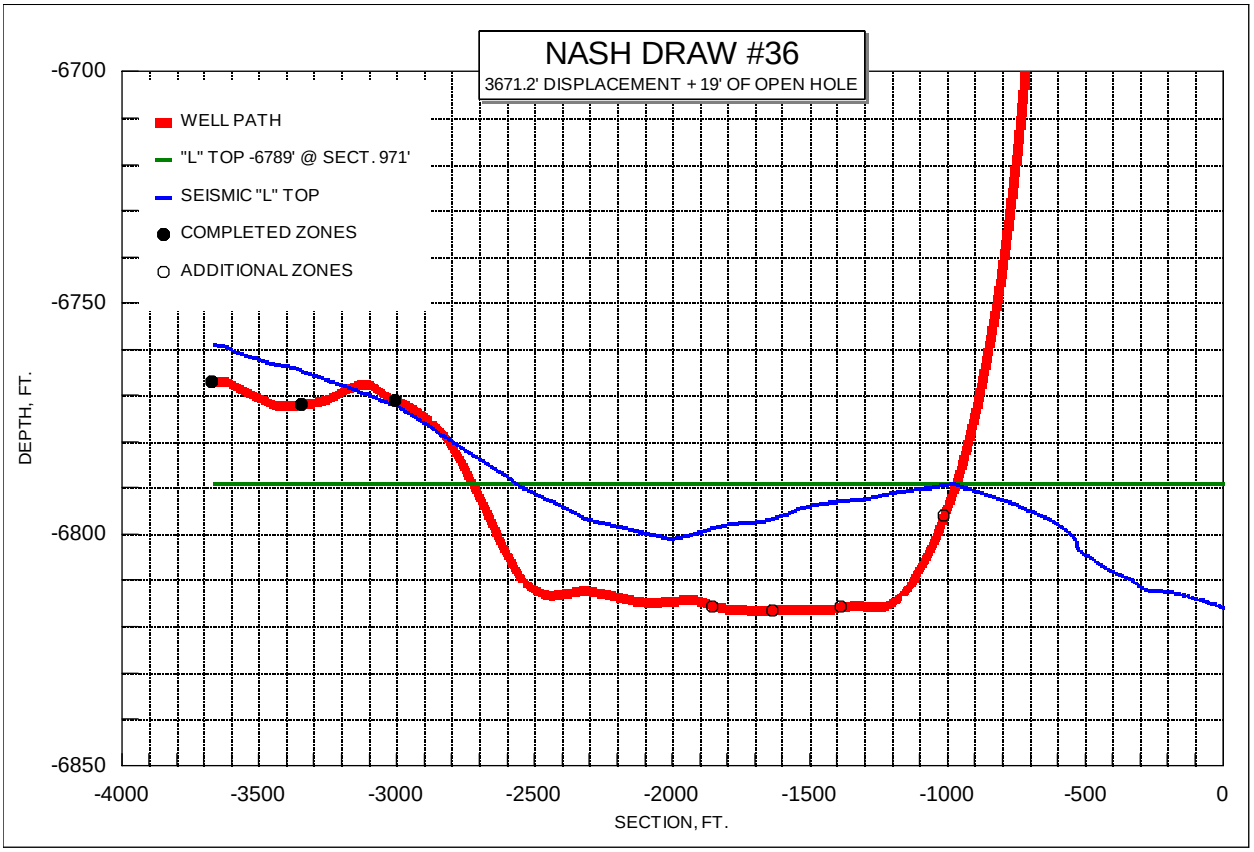

Fig. 1. Well path with completed zones and potential zones.

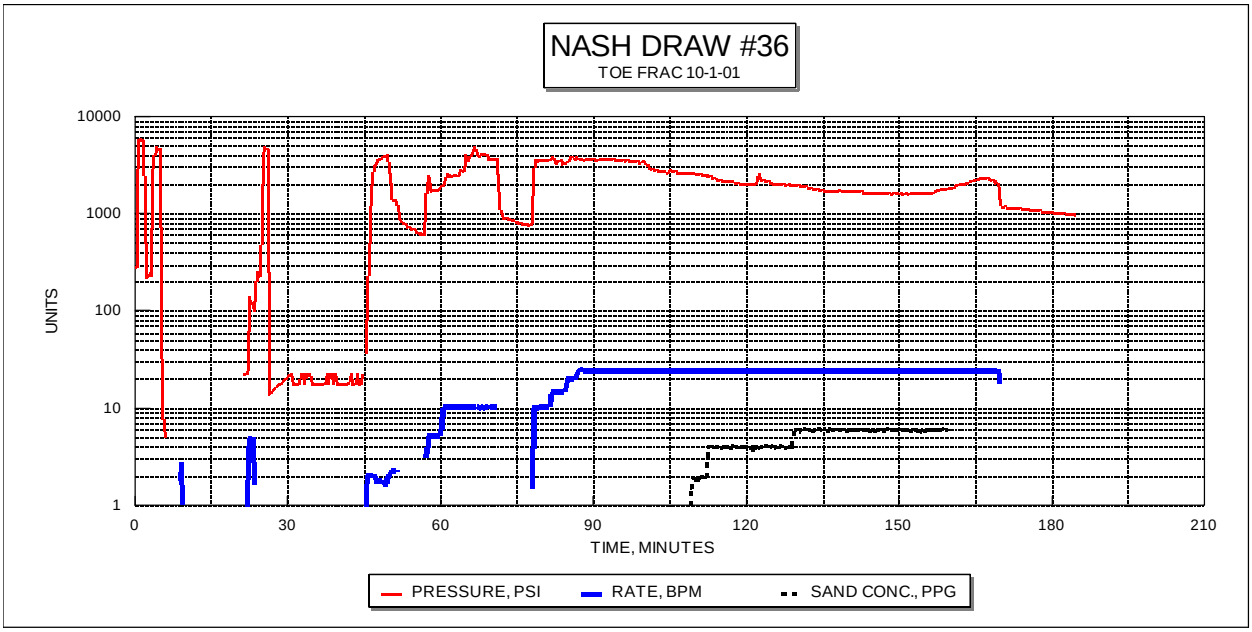

Fig. 2. Toe frac treatment.

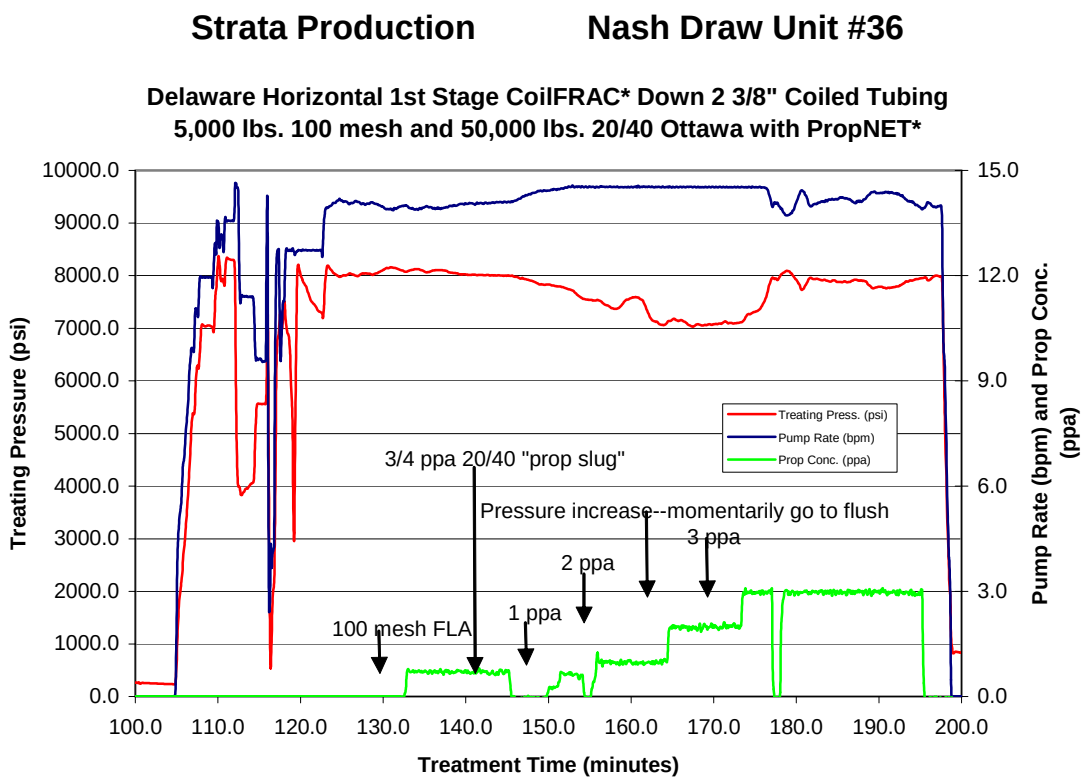

Fig. 3. First Mohave Frac Treatment.

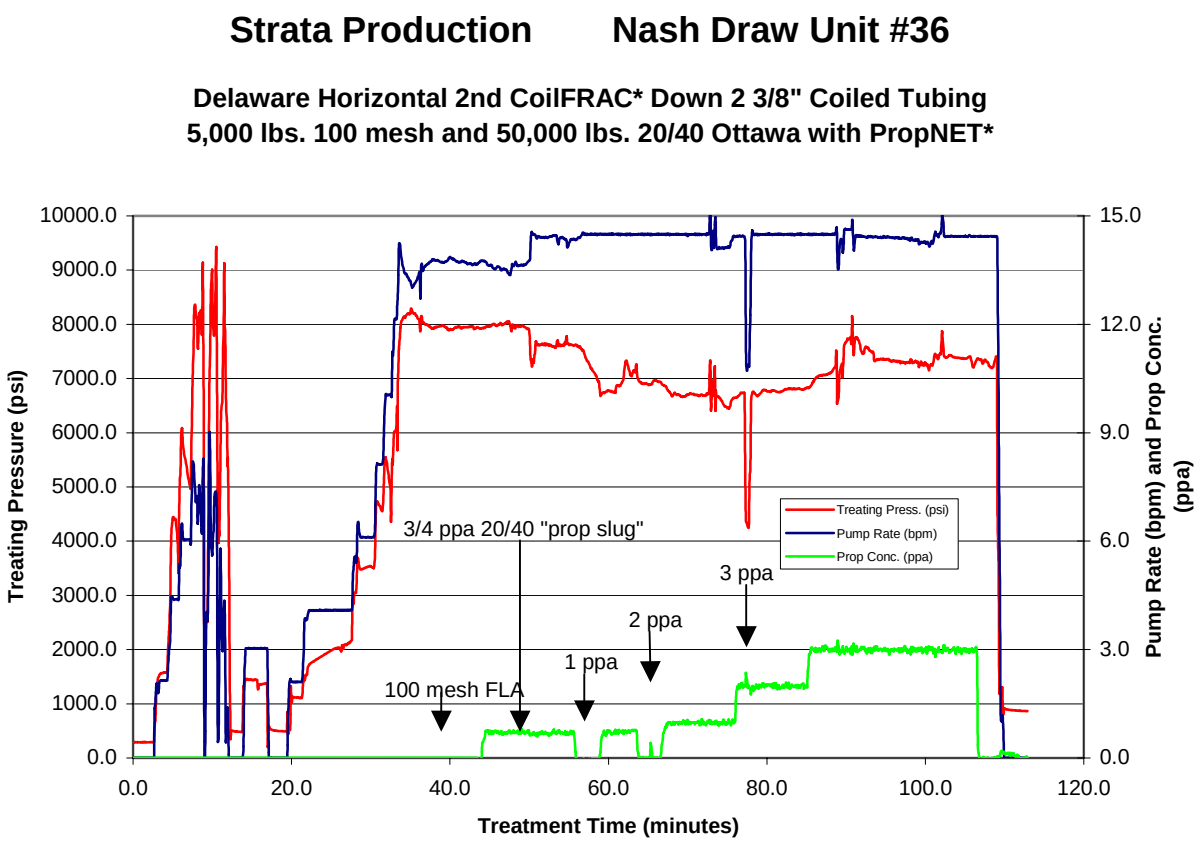

Fig. 4. Second Mohave frac treatment.

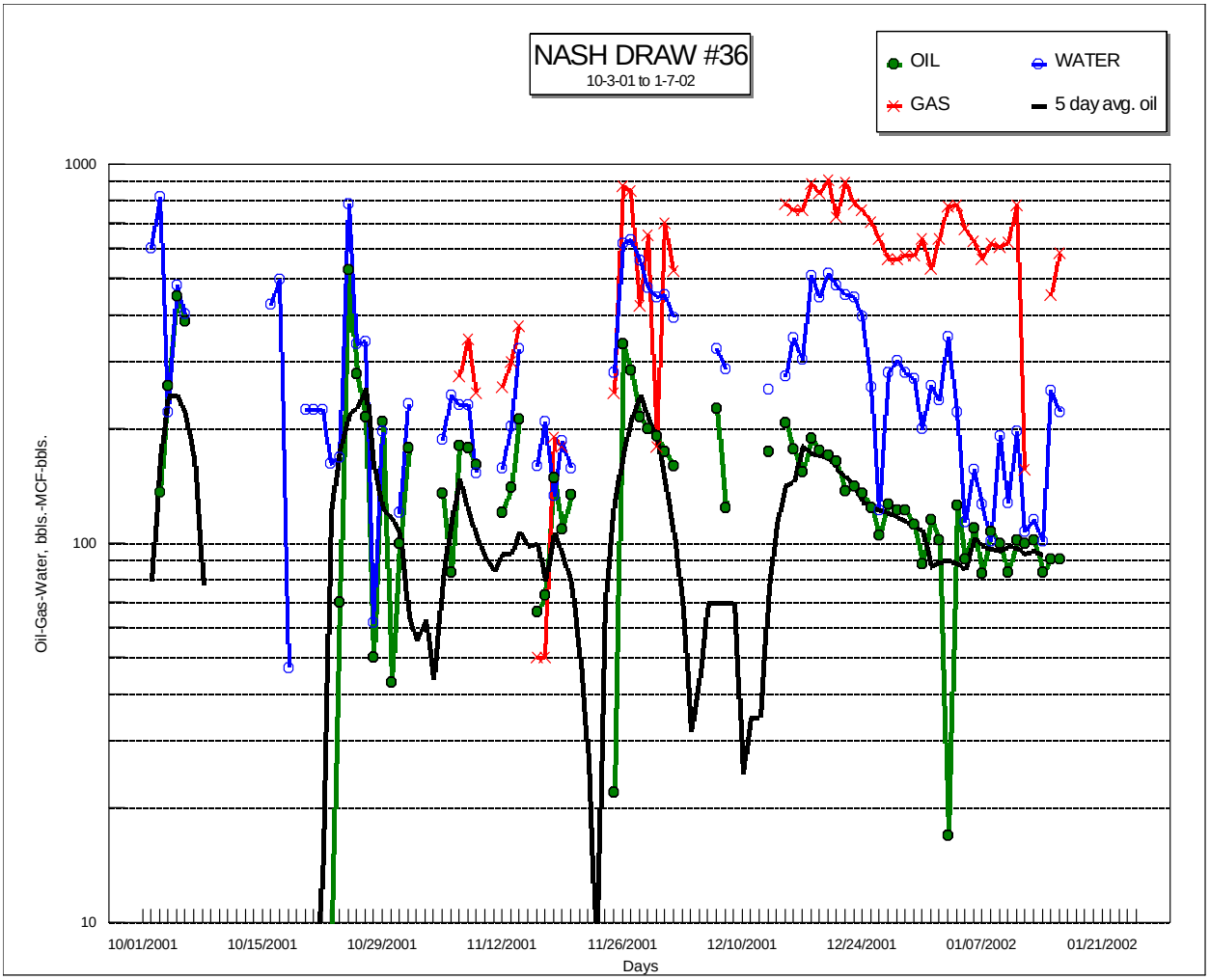

Fig. 5. Daily test rates.