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MPD Technique in Haynesville Shale Delivers Significant Value in Over Pressured Zones, A Case Study on Four Wells.

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Abstract

An MPD system was utilized in the Haynesville Shale in Red River Parish, Louisiana. This area is known for its difficult high pressure and high temperature drilling environment; with pressure gradients up to 0.9 psi/foot; which allow the wells to produce at high rates. Significant micro-fracturing, with resulting higher porosities and permeabilities was expected, with over pressured zones to be encountered.

The MPD system allowed for safer management of gas at surface during drilling operations, which was substantial due to the shale nature. During gas cut mud returns an influx of hydrocarbon was quickly detected and minimized with the system ability to manage surface back pressure. A modified driller's method of well control was utilized to safely minimize the influx volume, circulate out the influx, and deplete the interval in a matter of hours.

The MPD system was selected to provide early kick/loss detection and allow significant reduction in previously used mud weights in an effort to increase ROP.

Results obtained utilizing MPD on four wells drilled are discussed and presented comparing with conventional drilling techniques used on initial field wells.

Introduction

Shale gas has become an increasingly important source of natural gas in the United States over the past decade, and the interest has spread worldwide. The expectation is that shale gas will supply as much as half of the natural gas production in North America by 2020[1]. Due to shales nature of insufficient permeability, shale gas is considered as an unconventional gas sources and is known as "resource plays" as opposed to "exploration plays" due to the fact that geological risk of not finding gas is low[2]. However, rate of return is also low due to high costs of necessary applications such as horizontal drilling, completion and hydraulic fracturing for shale plays.

With advances taking place in horizontal drilling and multi stage hydraulic fracturing technologies, unconventional shale gas becomes attractive for the oil and gas industry. Reduction of drilling operation cost due to NPT and increasing the safety and handling of unforeseen drilling related events is a requirement for the safe drilling of shale gas.

Haynesville shale is a formation composed of consolidated clays and shales located in Northwest Louisiana and East Texas during upper Jurassic age and underlies Cotton Valley Group and Bossier Shale. It is characterized by ultra-low permeability, but high porosity compared to other shale plays along with a system of natural fractures and faults. It is estimated to be the largest unconventional natural gas field in United States with 250 trillion cubic feet of recoverable gas. The most productive areas for Haynesville shale plays are Desoto, Caddo, Bossier, Bienville, Red River and Webster parishes. An important aspect of Haynesville shale is its high temperature and natural fracture system. Due to its natural fractures, it is considered an HP/HT environment for drilling purposes.

Scope of Work

This paper presents a brief summary of Micro-Flux Control System (MFCS) utilizing a "detection and management" variant of MPD, and the techniques application in Haynesville shale play (particularly in Red River Parish) drilling operations. Four wells case studies, common problems, planned solutions, unforeseen events, and corrective actions to these events using the MPD techniques and beyond are presented.

Micro Flux Control System

MFC system operates in a closed-loop circulating system where a rotating control device (RCD) diverts annular flow through a MPD manifold away from rig floor. The system is simply based on MFC technology which is to identify the smallest possible magnitude of micro influxes or outfluxes within this contained, closed-loop, incompressible environment by using mass and volumetric balances[3,4,5].

MFC system simply consists of an RCD to create closed loop environment for return flow, MPD choke manifold which contains two PLC controlled drilling chokes, Coriolis type mass flow meter, with electronic and hydraulic control units known as ICU and HPU, respectively. In addition to the above, equipment data acquisition and remote control units such as high precision pressure sensors and computers are the main components of the system. Figure 2 shows simple flow diagram of MFC system.

The computerized control system uses proprietary algorithms to identify micro influxes/outfluxes based on real time well data monitoring including flow, density, pressure and other drilling related data and trend analysis. Real time changes in pressure and flow and any other drilling related abnormalities can be identified quickly and within minute levels compared to conventional drilling. The system can distinguish between surface versus downhole event and take automatic corrective actions by managing annular backpressure with a special automated choke manifold. The system was developed to adhere the definition of managed pressure drilling by IADC MPD/UBO committee and to enable the system capability across a broad range; from early kick detection to constant bottom hole pressure variant of managed pressure application, including dynamic mud weight management, and identification of drilling pressure window limits.

Challenges in Conventional Drilling in Haynesville Shales in Red River Parish

The operator company had drilled 6 wells in the area (See Fig 1) with conventional drilling techniques prior to investigating alternative drilling applications. The main challenge was economics, due to high well cost comprised of drilling related NPT, multi-stage hydraulic fracturing, increased acreage cost, and declined production rate. The strong initial production rate and improved drilling practices for high drilling efficiency to overcome NPT is thought to offset these economic challenges. High temperatures, approximately 375 °F while circulating, challenge the downhole tool life and performance along with existence of high pressure-low volume natural fractures. Moreover, rapid hydrocarbon depletion from natural fractures, entrained/nuisance gas during drilling, high background gas after connection, differentiating between these events from sustained influxes; and safely managing either of them in a controlled manner consistently challenged the play.

One of the most important challenges is ROP performance due to high mud weight. Reducing drilling time by increasing ROP with decreased mud weight, and not compromising well integrity including drilling pressure window and safety of the operation are the main objectives of the operator. This drove the decision to bring the MPD system with detection and management variant of flow & pressure based MPD for application in this area. Briefly the challenges and operator objectives to apply MPD with Micro Flux Control System can be summarized by;

- Required steady improvement of well drilling performance
- Maximizing on bottom drilling by reducing NPT
- Increasing ROP without trading-off safety and well integrity
- Safely handling unforeseen events in HPHT environment such as quick identification and circulation of rapidly depleting hydrocarbons from natural fractures, safely out of the hole
- Improve overall drilling efficiency

Project Objectives using Detection and Management Variant of MPD in Haynesville Shale Play for Four Wells Drilling Campaign

The Operator Company sought several benefits with application of MPD during the 6 1/8” hole section including vertical, curve and lateral drilling after setting 7”- 26 lb/ft intermediate casing. There were three main objectives from the operator points of view to reach the target without compromising safety and optimize drilling efficiency;

- Increase average ROP from 15-20 ft/hr to 40-50 ft/hr by reducing planned/used mud weight from 16.5 ppg to 14.8 ppg range unless the well dictates weighting up.
- Rapid gas depletion handling from high pressure-low volume fractures
- Early influx/loss identification and precise corrective action decisions such as safely circulating out entrained gas or influx more efficiently and in a controlled manner.

Based upon objectives and expectations from the operator, detection and management variant of MPD application was deemed more suitable than the CBHP variant of MPD during the planning phase of the project.

The system deliverables were discussed with the operator based upon drilling procedures, and the system can be used safely to improve drilling efficiency through Dynamic Mud Weight Management (DMWM), early influx/loss detection and optimize well-site operations in gas handling scenarios. In other words, using the system would deliver faster ROP and less non-productive time by its ability to precisely monitor and characterize very small changes in annular pressure and annular flow profile.

DMWM approach was used in verification of pore pressures and fracture gradients; also known as determination of drilling window limits in real time, while drilling. Thus improving ROP performance by maintaining mud weight around 14.8 to 15.0 ppg as opposed to 16.5 ppg and apply suitable corrective actions using surface back pressure unless the well strictly dictates mud weight increase. The system was used to perform quantification of transient gas events to avoid unnecessary mud weight increase, reduction of NPT circulating out nuisance gas/influx events such as rapid depletion, and improve decisions by providing better information to decision makers real time.

The system’s ability to trend the flow, density, and pressure data along with use of virtual trip tanks allowed early influx/outflux identification, and provided continuous real time well monitoring, and trend analysis to determine abnormalities of drilling parameters. Furthermore, utilization of active system alarms would facilitate early detection and allow quick response to downhole and surface events by operator personnel.

During the planning phase of the project, expectations of the system capabilities were established with the operator company representatives. Geologic features were identified and assessed for their potential magnitude and contingency plans with identified hand off points were discussed. Project technical challenges were clarified for wellbore limitations and instrumentation limitations. Alternative approaches were discussed in the event that the flow meter’s single phase limitation was exceeded. To avoid lack of event identification if high background gas was present in the meter, the use of high resolution pressure sensors and choke positions as well as rig data acquisition system were identified as an alternative approach.

Rig surveys were completed for 4 wells by well-site supervisors prior to operation and involvement of the well-site supervisors, drilling foremen along with the operator companies drilling team members was deemed essential key to success.

A Case Study for Four Wells

Forest Oil Corporation decided to drill 4 wells using MPD application with MFC system in Red River Parish-North Louisiana also known as Haynesville shale play. The operator company has drilled 6 wells using conventional drilling methods and wanted to compare the performance of MPD wells with conventionally drilled wells.

The generic drilling plan for the area was to set 9-5/8" 40# J-55 surface casing around 2,000' MD/TVD and then drill vertically 8¾" size intermediate hole to set 7" 26# HCP-110 LTC at approximately 10,500' MD/TVD. 6-1/8" hole section was planned to drill as a directional and lateral hole to TD approximately 17,000 ft MD/12,600 ft TVD. Kick off point was 12,100 ft MD/TVD to build the curve 8°/100' till trajectory reached lateral at 13,000' holding till TD(Total Depth). The 4 ½" production casing was planned to run after drilling completed.

Planned days from spud to TD was approximately 45 days. 6-1/8" hole section was planned to drilled within 31 days with 16.5 ppg OBM. The generic drilling diagram can be seen in Figure 3 for Haynesville shale play.

MFC system was utilized to drill 6 1/8" hole section for all four wells to fulfill and deliver project objectives. Original plan for drilling fluid for MPD application was to keep and maintain 14.8-14.9 ppg OBM.

Well A

The plan for the first well in May 2010 involved drilling the 6 1/8" hole section from 10,712' (3,265 m) to 17230 ft total depth. The kick-off point was drilled out of the 7" 26# casing shoe at 10,712', and an FIT of 17.5 ppg equivalent was performed at 10 ft below the casing point.

While previous wells had been drilled out with 16.5 ppg OBM, use of MFC led to exiting the shoe with 14.8 ppg OBM with the objective of holding that mud weight to TD. Drilling proceeded with hole angle built at 8°/100' (30 m) to horizontal.

The lower mud weight improved ROP. While previous wells were drilled at 12-15 ft/hr average ROP with 16.5 ppg mud, the reduction to 14.8 ppg increased average ROP to 40-50 ft/hr (12 m/hr).

While gas presence was significant during operations, drilling was routine and the system performed as planned without any significant problems such as rapid depletion or well control events. The system clearly and accurately identified small variations such as connection gas and other standard oscillations in pressure and flow. One of the most important approaches was when connection gas reached near to surface it started to break out of solution and expand. When gas near surface event occurred, SPP (Stand Pipe Pressure) started to decrease slightly depends on gas amount and expansion rate of the gas in the drilling fluid. In order to offset this effect, initially 100 psi SBP (Surface Back Pressure) was applied to the annulus to compensate reduction on SPP based upon the approach of the second circulation of Driller's method in order to avoid losing hydrostatic head of mud due to expansion, also known as "keeping the Stand Pipe Pressure constant". If reduction on SPP was more than initial 100 psi, then SBP was increased to keep SPP constant. The summary of MPD application of Well A can be seen in Table 1.

Well A reached TD in 16 days versus the planned 31 days, even with two days of NPT recorded due to unrelated rig service problems. In addition to faster drilling, there were associated savings in fluid costs due to lower mud weight. Time distribution for Well A 6 1/8" MPD operation can be seen in Figure 4. Some of the event identification screenshots related to Well A can be seen in Figure 5 to Figure 9.

Well B

The 6 1/8" section of the Well B was planned as a horizontal hole to 16739', with an intermediate casing at 10,587' and a 4 ½" production casing at 16737'. In the case of source rocks like the Haynesville, with excellent vertical and lateral seals with Bossier Shale in upper section (approximately 12,400') and Haynesville Lime (approximately 12,600'). Moreover, with significant natural micro fractures in the transition zone between Bossier Shale to Haynesville shale and in the Haynesville shale, gas influx was likely to occur while drilling the well. Low volume-high pressure natural micro fractures caused influxes and quick depletion during the drilling operation.

MFC application was contracted for 6 1/8" section for early kick detection and to help keep a reduced MW for increased ROP. Two main purposes for drilling this section were early kick detection and control (depletion included) and higher ROP compared to previous wells which had been drilled in the vicinity. MicroFlux Control System operations were applied for the 6 1/8" section including vertical and directional and lateral parts of the application, with the range of 14.8 ppg-15.5 ppg oil base mud. The last 300 ft of the well was drilled with increased mud weight (from 15.0 ppg to 15.5 ppg) due to expected high pressure faults and micro fractures which had decreased ROP from 60 ft/hr to 18-20 ft/hr for last two days due to equipment pressure ratings and additional frictional pressure in the well. Total drilling time with the system took 16 days from the beginning of the well to TD including wiper trip and POOH (Pull Out of Hole), comparing to planned drilling days to TD which was 30 days (48% Reduction). The 16 days included an 18 hours depletion event. (See Figure 10-11) MPD operation summary in Well B can be seen in Table 2.

Operator's expectations were achieved and verified the system's reliabilities within its limits. Continuous training, with a flexible (open minded) operational approach was accepted and operational procedures were adjusted for new possible challenges while conducting operations. Crew competency and adaptable decision making capabilities in this challenging environment have been noted as requirements for continuous training and lesson learnt from this project. Other than having an operational equipment failure (busting downstream hose and valve isolation problem on location) for a short time period, no major incident happened during operations.

From Forest Oil point of view, the service worked after depletion zones were detected, the gas related to this depletion was circulated out using the system in a controlled manner; increases in mud weight were no more than 0.1 ppg in the majority of the drilling process.

Connection / Background Nuisance Gas Handling

The system was used to handle connection and background gas safely in a control manner. During drilling in the transition zone (building a curve from vertical to horizontal) between Bossier shale to Haynesville shale, high amount of connection gas was experienced after each bottoms up. Annular Friction Pressure (AFP) during circulation with 250 gpm flow rate was around 800-900 psi due to tight clearance of annulus. During connections, annular pressure exerted against wellbore was decreasing due to loss of annular friction. Due to low permeability of the matrix, connection gas was not extreme and the hydrostatic pressure during connection was not underbalanced but near balanced. Therefore, the procedure applied to handle connection gas after bottoms up circulation was to apply 150 psi at the surface and monitor SPP carefully in order to keep SPP constant when connection gas came near surface and started expansion. Expansion of the connection gas may have reduced SPP and that may have created loss of hydrostatic head. If SPP decreased more than applied 150 psi, increases in back pressure corresponding to the SPP decrease rate and monitoring of SPP/return flow rate and return fluid density was done to verify the event of connection gas at the surface. This procedure for gas handling and diverting the return flow to the rigs MGS, increased safety and enhanced connection/background nuisance gas handling during drilling without increasing the mud weight and without any gas handling related NPT (Non Productive Time). Also, there was a distinct signature and alarm of gas expansion in the system for verification and corrective actions when required. Several connections with gas/rig service related nuisance gas screenshots can be seen on Figure 12 and Figure 13 for Well B.

Rapid Depletion from High Pressure-Low Volume Natural Fractures

While drilling at 12288', an observable divergence between flow in and out was shown on the MFC system representing a quick depletion event from the high pressure low volume fracture. 97 gallons of gas depleted within 2 minutes and simultaneously increased SPP 400 psi. After 2 minutes flows equalized and then depleted hydrocarbon started rising in the annulus. By that time, there was a pipe movement. Anomaly on the flow and pressure was told to driller- driller kept circulating and continued drilling. Later on 40 min when the gas was near to surface, indication of expansion was observed (43 psi was observed in the choke while it is 100% open- normal rate is 25 psi). Immediately applied 100-150 psi SBP on top of it and circulated the gas in a controlled manner. When gas hit the choke it created 400 psi while passing thru a 100% open choke. The choke was then pinched back more creating 500-600 psi to circulate gas out in a controlled manner. After the circulation was finished, the choke was opened to 100% and saw that system back pressure was 100 psi. This is another observation for another anomaly… Walk thru the lines and observed that one of the butterfly valve connected to MGS lines was ¾ closed due to gas passing thru. The valve was opened back to 100%, and secured. This reduced the back pressure to 25 psi which was nominal system back pressure due to plumbing. This event can be seen in Figure 14.

Kick Event: Identification, Circulating and Depletion Effort

12326 ft depth, MFC system observed flow out is diverging from flow in. At this time, Auto Control detection function was active. Unfortunately, at the same time, fluid density started decreasing indicating that nuisance gas was at the surface. The Microflux system recognized this event as gas at the surface event and did not apply back pressure automatically. When experienced operational personnel figured this out, it was determined a "kick event and gas at the surface event coincided" by checking increased SPP. Within 20 second 200 psi SBP was applied, and gradually increased 650-700 psi to control the kick. All the time the intention was keeping the SPP not less than 3500 psi in order to keep bottom hole pressure around 16.9-17.0 ppg equivalent (10900-11000 psi). By the time, company man is informed, we had a kick, stop drilling and pick off bottom. FIT was 17.5 ppg and MASP (Maximum Allowable Surface Pressure) was equal to 800 psi. Even though, SBP was gradually increasing due to expansion and approaching the MASP high limit (750 psi and assumption is made the gas column was still below the casing shoe), it was obvious that the kick was not under control by monitoring flow in/out. The required pressure to control the kick and circulate the kick out was beyond the MASP limit with full circulation rate. Pressure was still building up on the choke drastically due to gas expansion. Decision was made to hand over the well to rig choke manifold. The well was shut in on MPD chokes and on annular BOP and pipe rams. The reason to shut the well in on MPD choke was to see SICP on high resolution pressure sensors. The pressure immediately reached 800 psi within seconds and was still climbing up. PVT was indicating that 28 bbls of total pit gain occurred, but later on PVT gets stabilized after kick is handled indicating the 28 bbls was including the gas expansion. (The real kick amount identified as 3-4 bbls)

After shutting the well in conventionally, kick was circulate out based on rig choke gauge reading, with conventional well control. We kept SPP around 2200 psi with 45 SPM slow pump rate, even though MPD sensor SICP pressure reading was higher (in comparison; MPD gauge was reading 800 psi SICP, while rig choke panel was reading around 510 psi for SICP). Conventional circulation carried on several times at slow circulation rate of 45 SPM and then went up to drilling rate without any success on reducing casing pressure. The reason was identified that the rig choke panel gauges were not reliable, and the control mechanism of the rig choke was also malfunctioning.

After a conference call with Forest Oil drilling team, the decision was made to hand over the well to the MPD manifold, and try to deplete the high pressure low volume fracture by using a modified Driller's method and MFC system without increasing the mud weight, if possible. The re-written procedure for depletion was shut the MFC choke against the well, divert the flow to MPD manifold, open the BOP, bump the float, read SIDPP and SICP using MFC pressure sensors, calculate ICP, open the choke for 3 minutes to allow depletion, then reach ICP by closing the choke and keep SPP constant at ICP. Assumption had been made that the gas column was now above the casing shoe and calculated MASP using just liquid phase in the annulus (800 psi) during drilling was not applicable. This meant that more than 800 psi could be applied on casing pressure to circulate the kick out.

The MFC choke was shut in and annular was opened in order to read the first SIDPP and SICP using MFC pressure sensor prior to bump the float (SIDPP=510 psi, SICP=860 psi were recorded). After bumping the float valve in the drill string, SIDPP= 892 psi and SICP=942 psi was recorded. Using drilling rate off bottom SPP was around 3100 psi. Then ICP was calculated using,

According to this calculation; ICP was calculated around 4000 psi. At first circulation, maximum casing pressure observed was 1300 psi in order to keep ICP at 4000 psi. After the first circulation, the same procedure was applied 4 times, after we had verification that casing pressure was decreasing at the end of the first circulation. The 4 cycles of depletion (using full drilling rate) took around 6-8 hrs, and it was decided that fracture was completely depleted since there was no casing pressure observed. Related screenshots are seen on Figure 15 to Figure 16.

After the depletion was done, mud weight was increased 14.9 to 15 ppg and drilling resumed. For the next 6 connections, 500-600 SBP was applied to the annulus during connections to be on the safe side. Figure 17 shows that applying pressure during the connection. After dynamic pore pressure test was performed, the operator stopped application of back pressure during connections. Drilling was completed and the well called TD at 16737 ft within 16 days compared to estimated 30 days for 6 1/8" section.

Well C and Well D

The same approach of MFC technology was applied on the last two wells. ROP increased to 50-60 ft/hr by keeping MW to 14.8 ppg. There were no significant events observed on those two wells except for one rapid depletion and connection gas handling. Therefore, we decided not to mention last two wells in this paper due to events resemblances.

Conclusions

Utilizing MFC system in Haynesville shale play resulted in;

- Project objectives were successfully achieved.
- Overall drilling time within four wells reduced 49% over the four wells.
- More time on bottom drilling resulted in a step change in drilling performance. More utilization of motor life due to time spent drilling and not circulating at high temperature (see Figure 18-overall 10 wells in the area)
- Safety was enhanced with Micro Flux Control system due to its closed loop nature and managing large quantities of gas at the surface
- Early influx detection and circulation capability of the system increased overall drilling efficiency by reducing related NPT
- Nuisance gas management capability was enhanced.
- MPD Instrumentation supplemented Operator's well control processes and augmented existing well control instrumentation. Coriolis meter identified flow changes even in a high gas environment.
- Improved ROP at curve and lateral sections by allowing and maintaining lower mud weights compared to conventional approach.
- Precise choke control enabled ability to deplete the high pressure-low volume fractures within hours.
- Saved more than 2 million USD over four wells for the operator company.
- Dynamic Mud Weight Management was effectively established.

Acknowledgments

The authors would like to thank Weatherford International and Forest Oil Corporation for their permission to publish this paper and their encouragement to do so.

Nomenclature

MPD = Managed Pressure Drilling
ROP = Rate of Penetration, ft/hr
NPT = Non-Productive Time, hrs
MFC = Micro-Flux Control
HP/HT = High Pressure/High Temperature
PLC = Programmable Logic Controller
ICU = Intelligent Control Unit
HPU = Hydraulic Power Unit
IADC = International Association of Drilling Contractor
UBO = Under-Balanced Operations
DMWM = Dynamic Mud Weight Management
CBHP = Constant Bottom Hole Pressure, psi
MD = Measured Depth, ft
TVD = True Vertical Depth, ft
TD = Total Depth, ft
POOH = Pull Out of Hole
FIT = Formation Integrity Test, ppge
AFP = Annular Friction Pressure, psi
MGS = Mud Gas Separator
MASP = Maximum Allowable Surface Pressure, psi
BOP = Blow-Out Preventers
SBP = Surface Back Pressure, psi
SPP =Stand Pipe Pressure, psi
SICP = Shut-In Casing Pressure, psi
SIDPP = Shut in Drill Pipe Pressure, psi
ICP = Initial Circulation Pressure, psi
PVT = Pit Volume Totalizer
ppg = pounds per gallon
bbls = barrels

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Tables

Table 1: Well A MPD Summary

Description	MPD Section 1
Hole Diameter	6 1/8”
From Depth (MD)	10,712 ft (3,265m)
To Depth (MD)	17,230 ft
Starting Date	5/14/2010
Final Date	5/30/2010
Type of Mud	OBM
Flow Rate	240gpm
Minimum MW	14.8ppg
Maximum MW	14.9ppg
Initial Rheological properties (PV/YP)	42 / 17
Final Rheological properties (PV/YP)	66/24
Min ECD	15.5
Max ECD	16.1
Min Backpressure while drilling	25 psi
Max Backpressure while drilling	28 psi
Min Backpressure during connections	25 psi
Max Backpressure during connections	300 psi
Min Backpressure while tripping	25 psi
Max Backpressure while tripping	25 psi
Average ROP	40-60 ft/hr

Table 2: Well A MPD Summary

Description	MPD Section 1
Hole Diameter	6 1/8”
From Depth (TVD/MD)	10,587 ft
To Depth (TVD/MD)	16,737 ft
Starting Date	May 21 2010
Final Date	June 8 2010
Type of Mud	OBM
Flow Rate	240-250 gpm
Minimum MW	14.9 ppg
Maximum MW	15.7 ppg
Initial Rheological properties (PV/YP)	36 / 7
Final Rheological properties (PV/YP)	48/18
Min ECD	15.5 ppg
Max ECD	17.6 ppg
Min Backpressure while drilling	21psi
Max Backpressure while drilling	200 psi
Min Backpressure during connections	18 psi
Max Backpressure during connections	600 psi
Min Backpressure while tripping	8 psi
Max Backpressure while tripping	100 psi
Average ROP	40-50 ft/hr

Figures

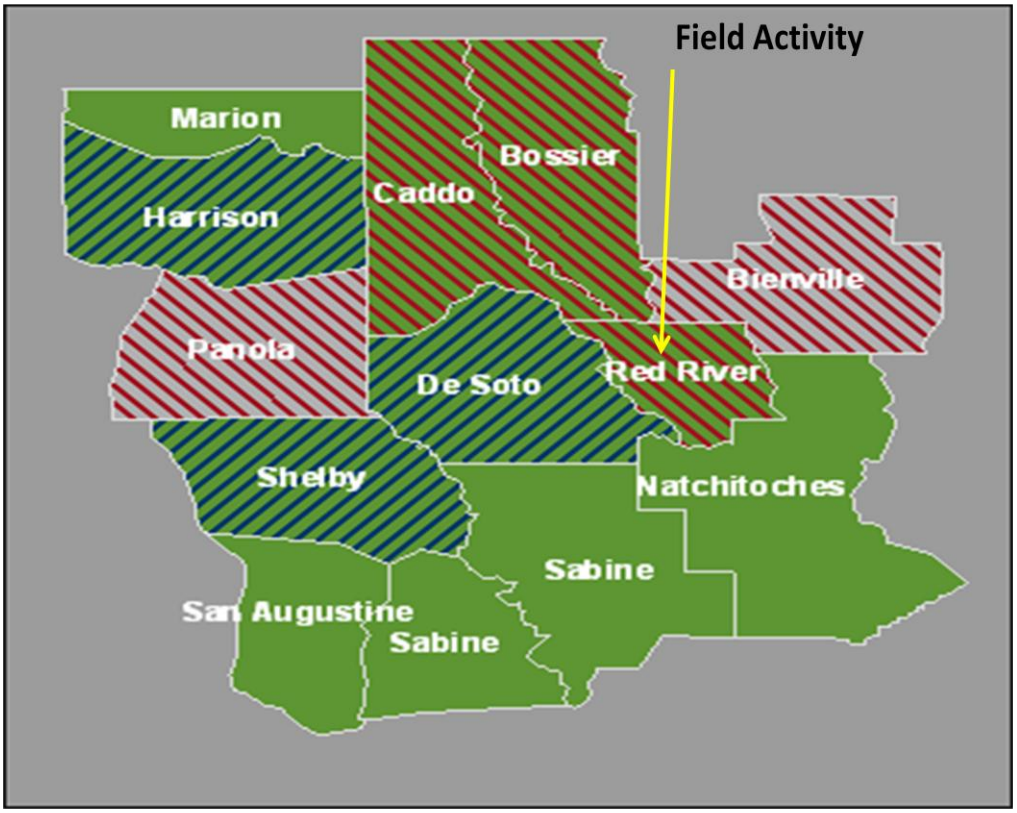


Figure 1: Area of Interest in Haynesville Shale Play

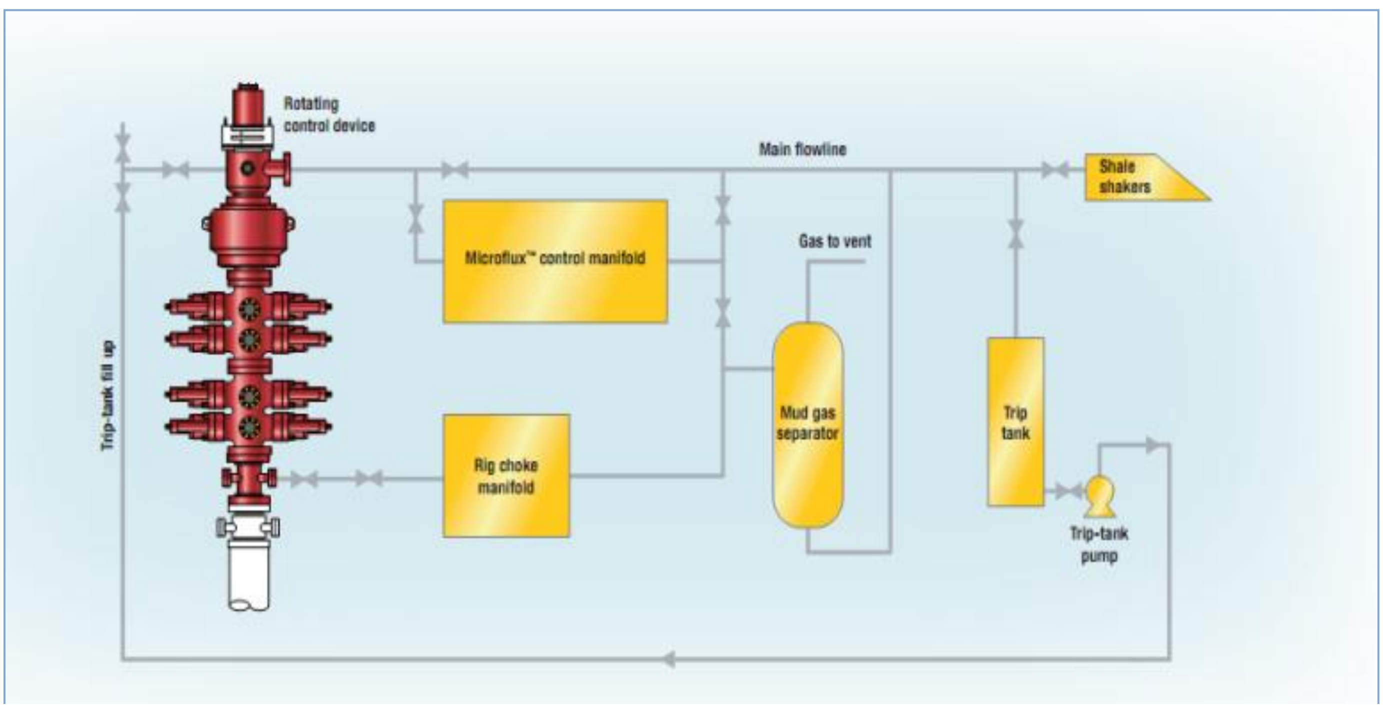


Figure 2: Simple flow diagram of MFC System

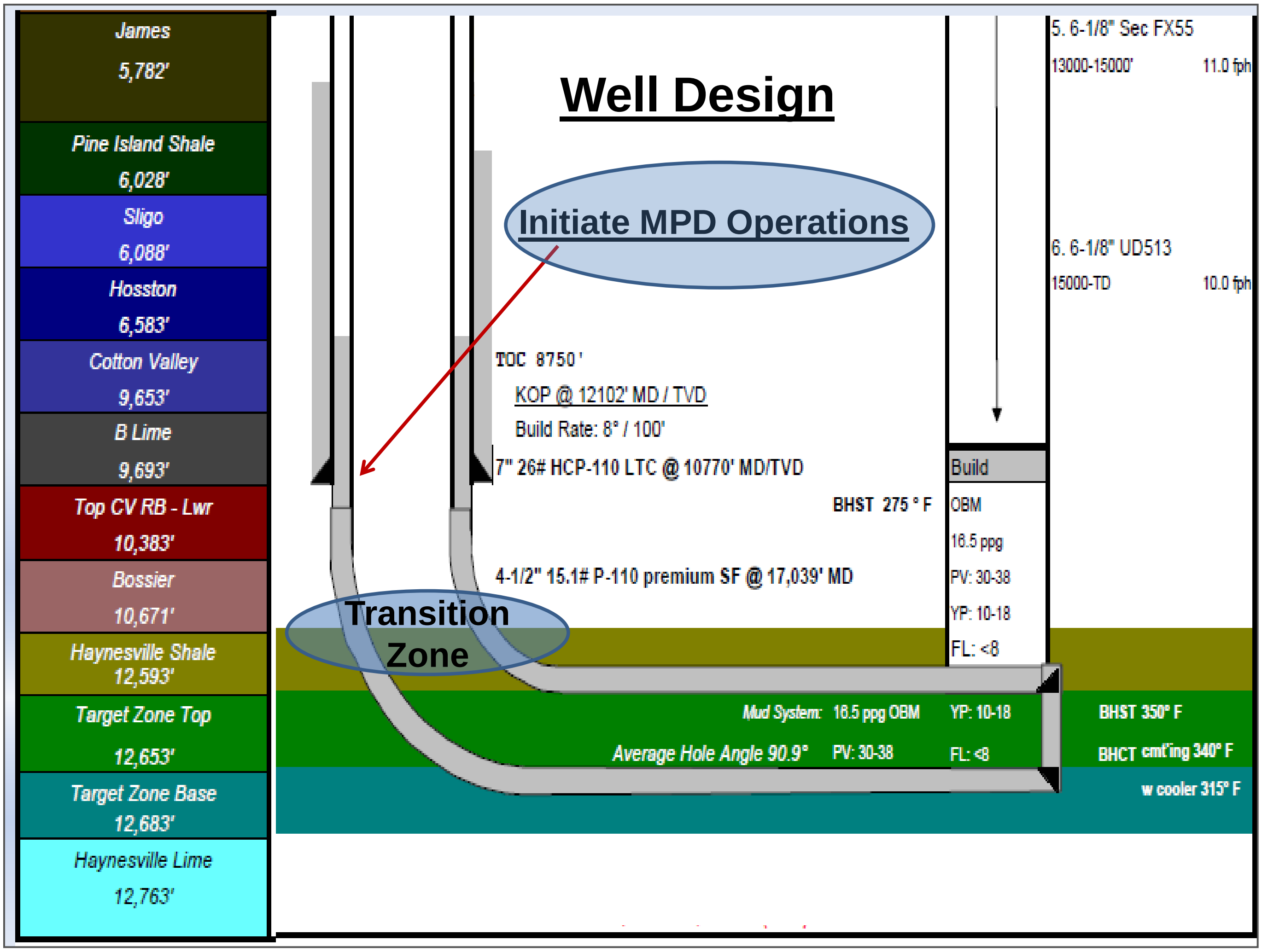


Figure 3: Generic well diagram for Haynesville Shale Play

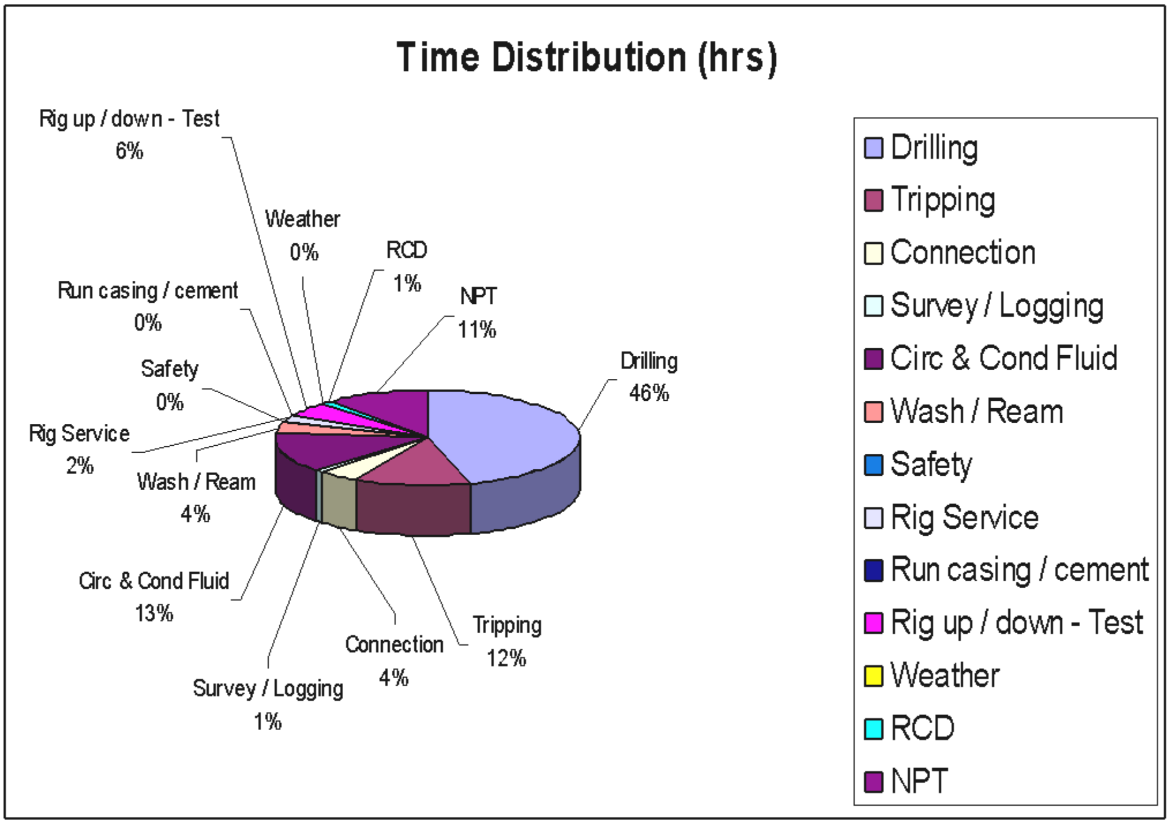


Figure 4: Well A MPD application, time-breakdown of 6 1/8" section

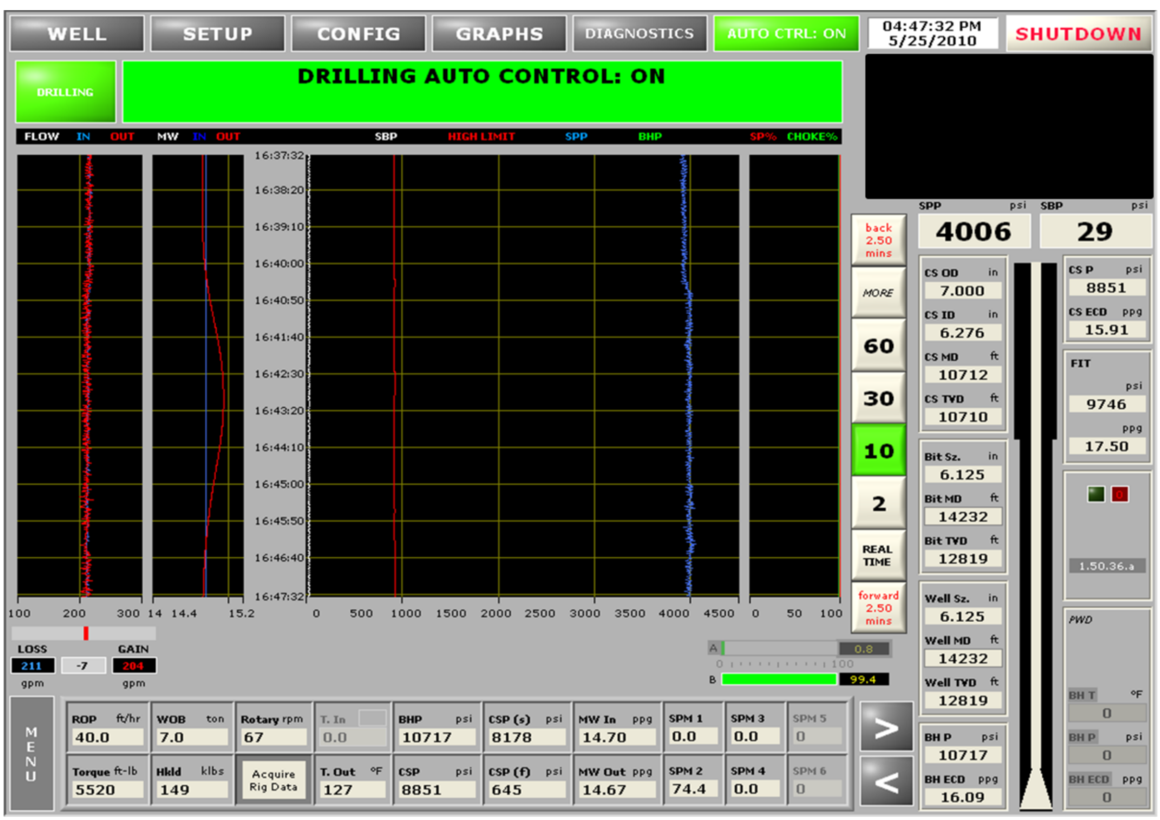


Figure 5: Sweep is passing through flow meter (MW increase confirms sweep is at surface)

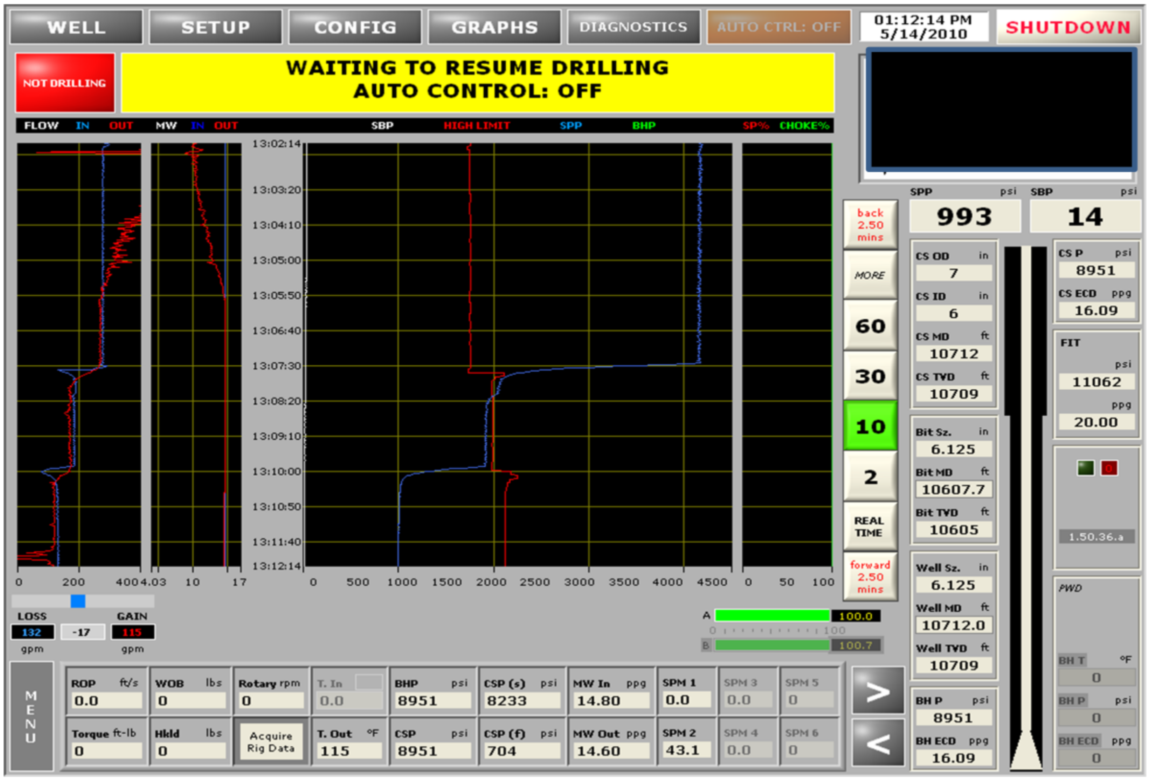


Figure 6: Different pump efficiencies for different flow rates

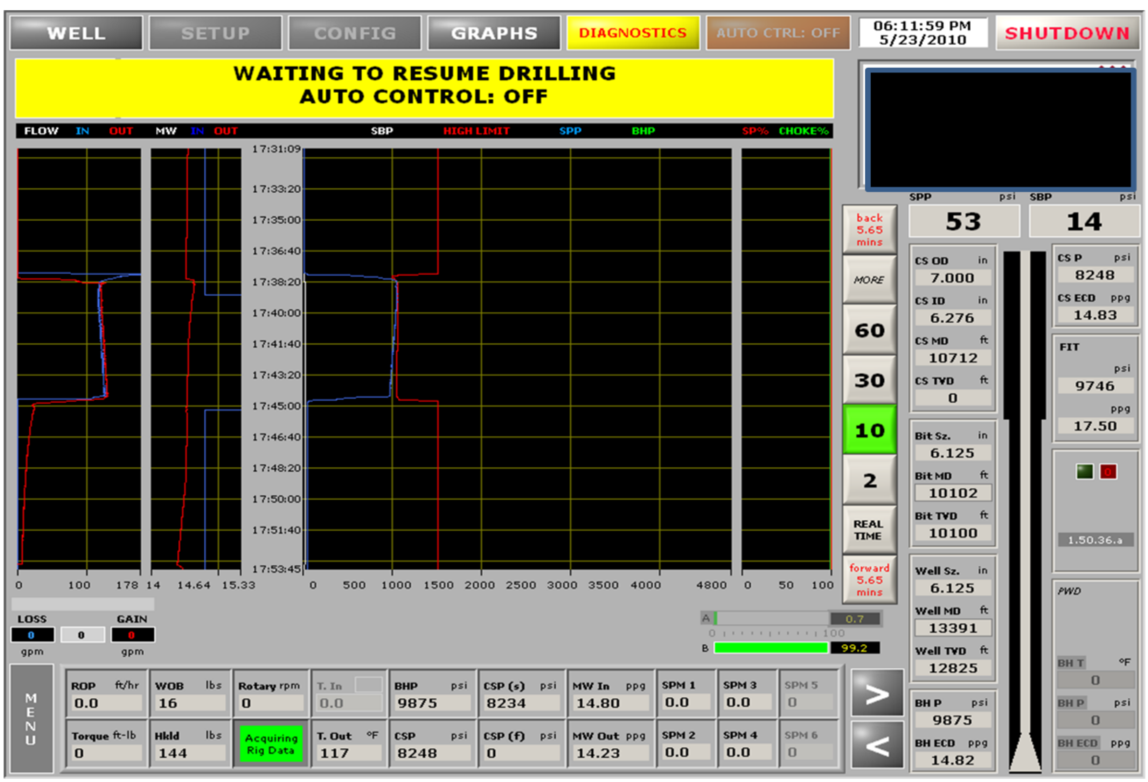


Figure 7: Pumping slug and U-tubing (Flow Out doesn't go to "0" until U-Tubing is complete)

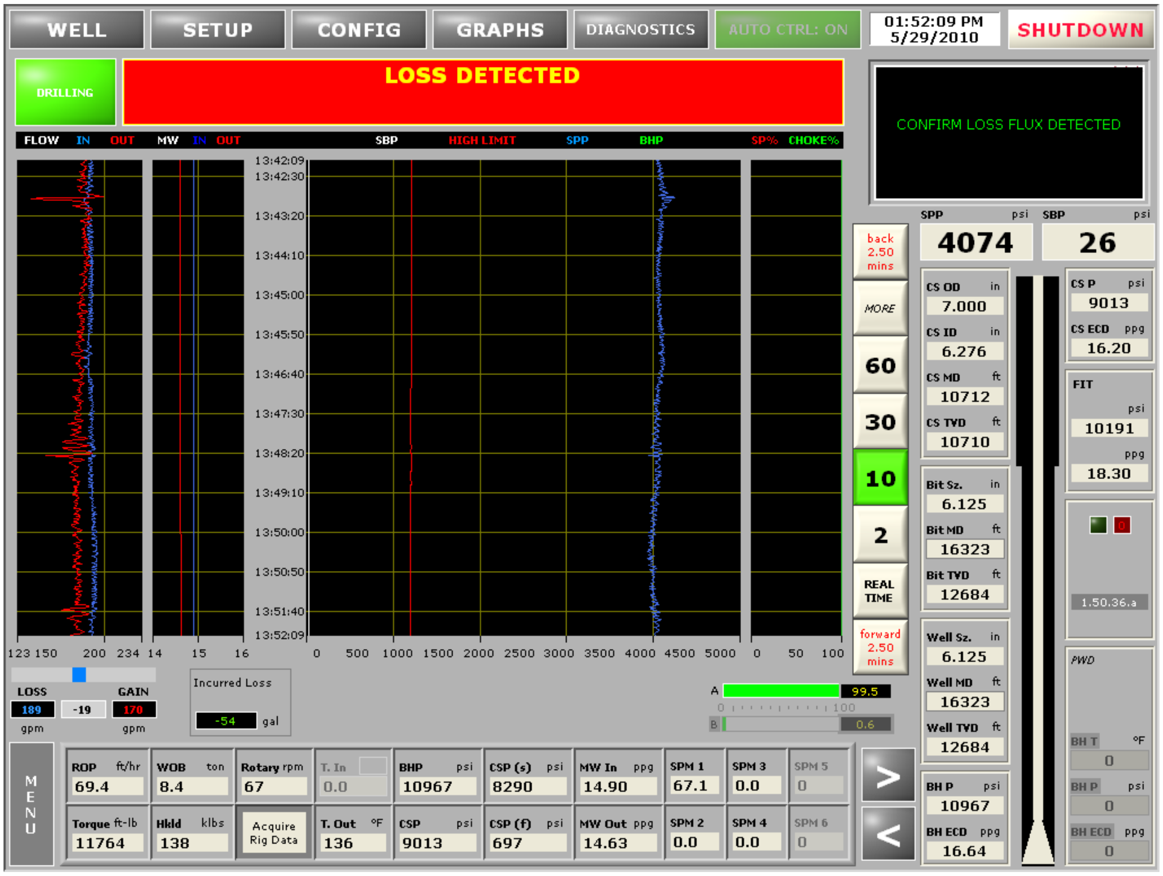


Figure 8: Loss detected (RCD is leaking)

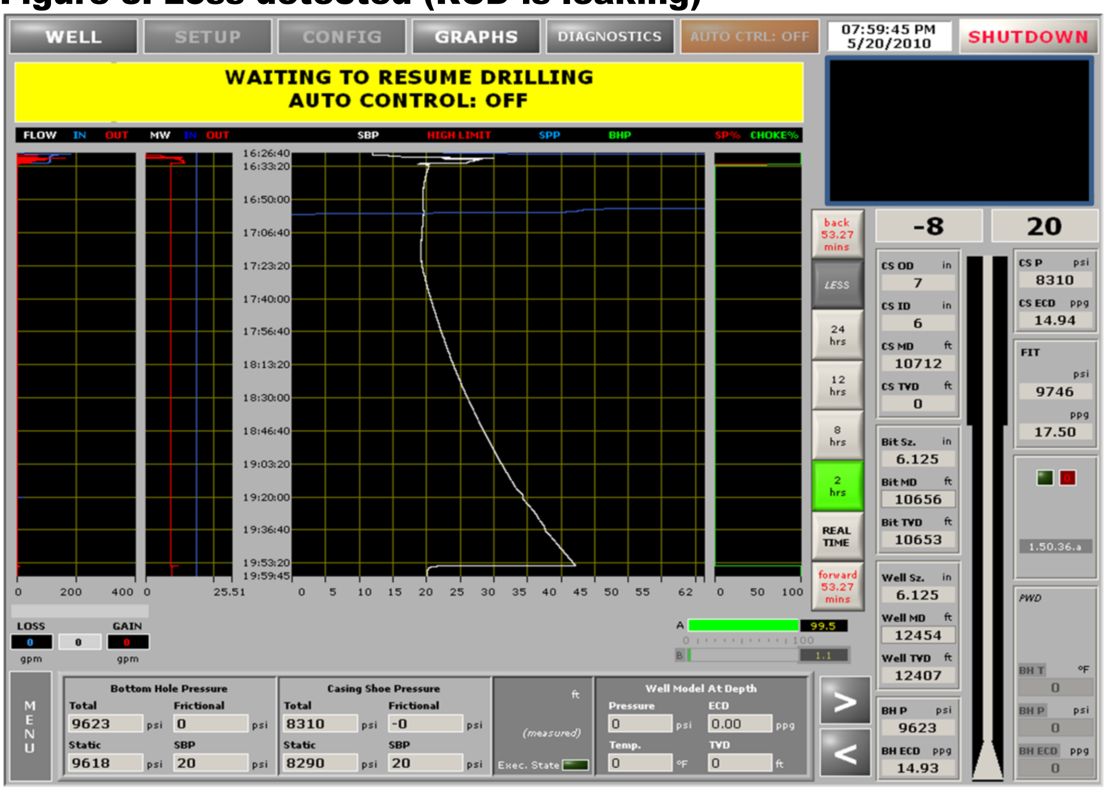


Figure 9: Pressure build up after Shut-in the well against MPD choke (accurate SICP reading)

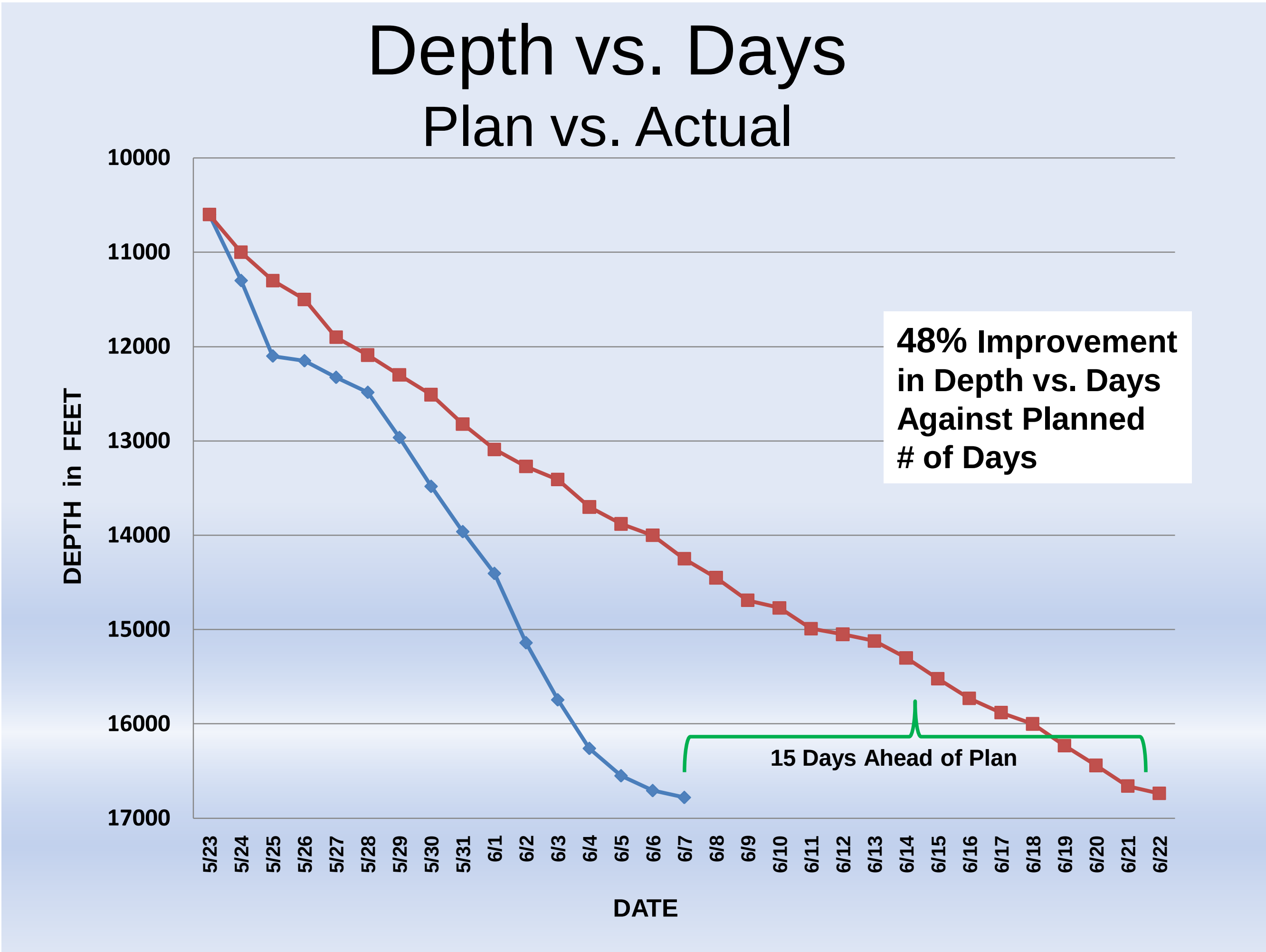
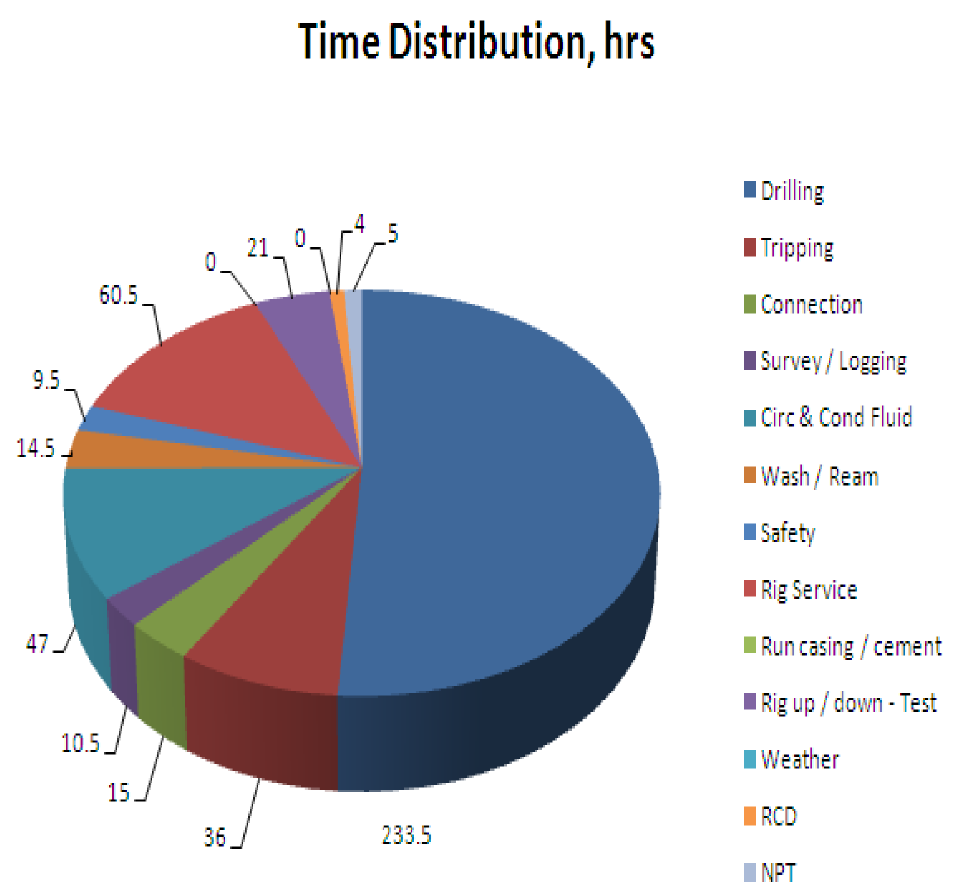


Figure 10: Well B MPD performance, Depth vs Days



Item	Time	
	Hours	Days
Drilling	233.5	9.7
Tripping	36	1.5
Connection	15	0.6
Survey / Logging	10.5	0.4
Circ & Cond Fluid	47	2.0
Wash / Ream	14.5	0.6
Safety	9.5	0.4
Rig Service	60.5	2.5
Run casing / cement	-	-
Rig up / down - Test	21	0.9
Weather	-	-
RCD	4	0.2
NPT	5	0.2
total	456	19.0

Figure 11: Well B MPD application, time-breakdown of 6 1/8” section.

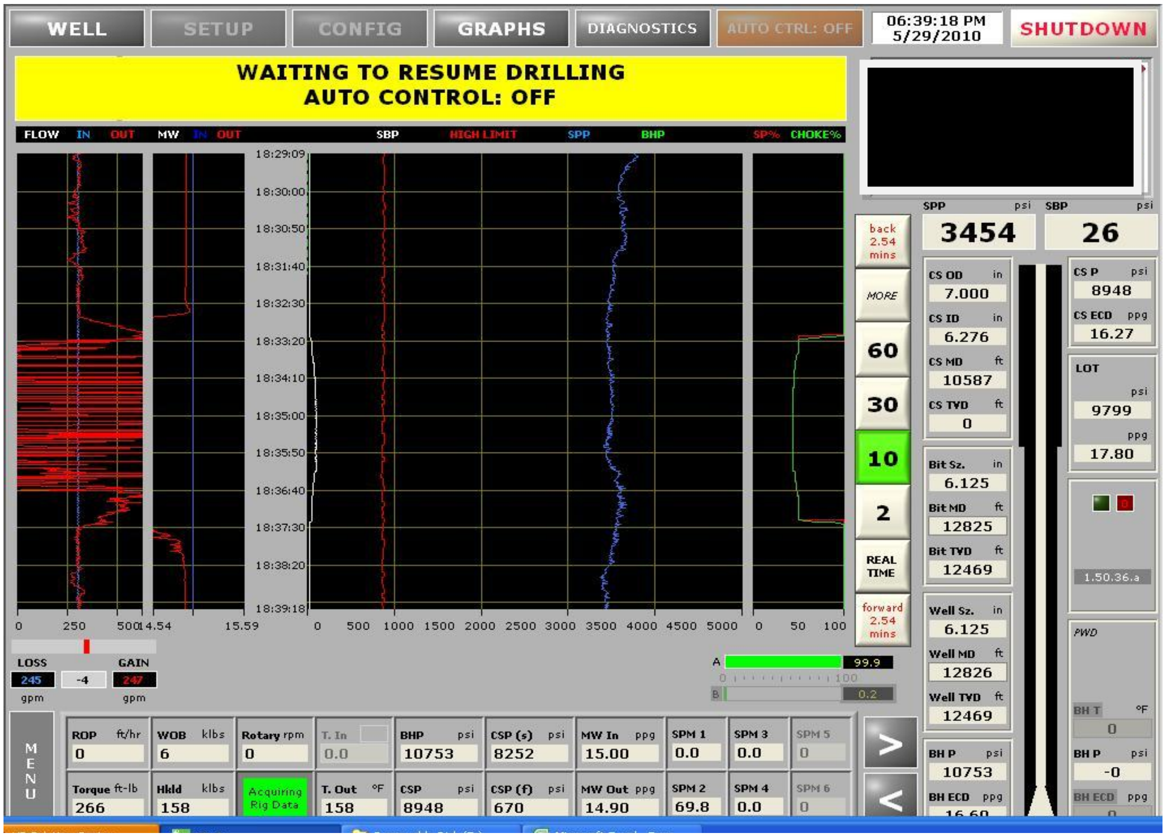


Figure 12: Enhancing connection gas handling at the surface with the system at Well B. 150 psi applied at the surface to compensate loss of SPP due to gas expansion.

Figure 13: Gas at the surface due to 1 hr rig service, took 6 min. Max gas is 400 unit.

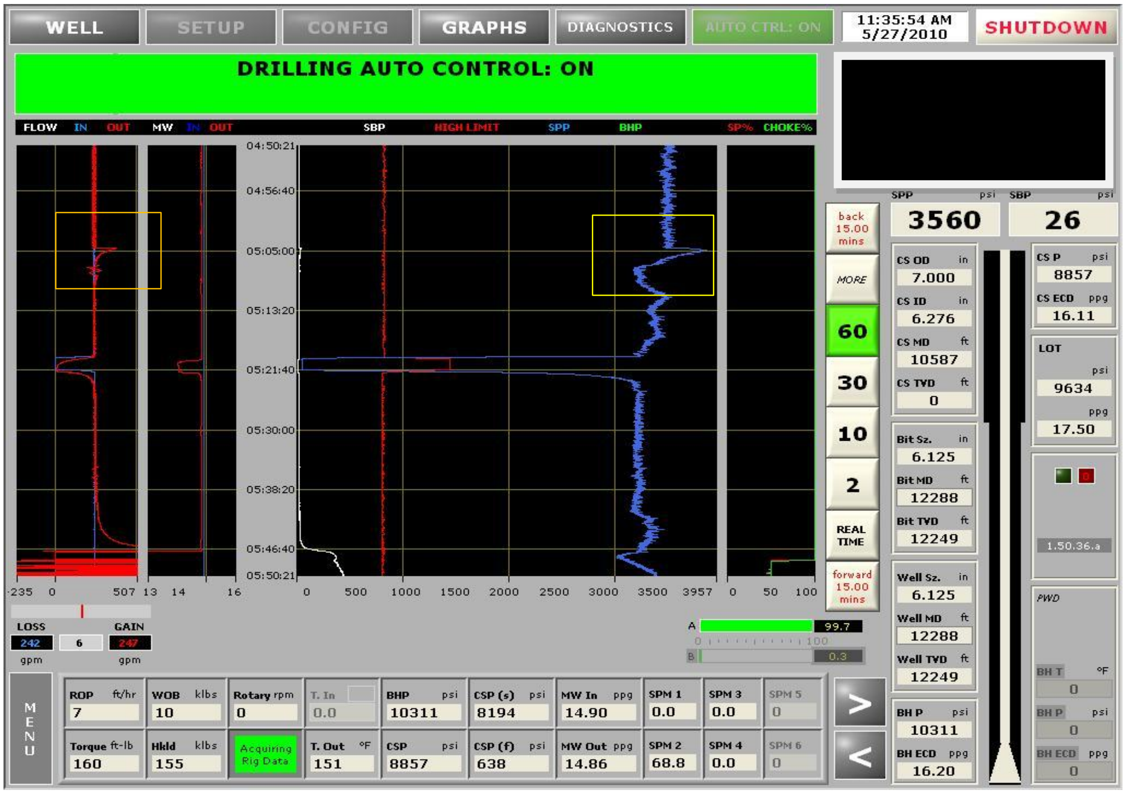


Figure 14: 97 gallons quick depletion within 2 minutes-SPP increased 400 psi initially and then DP pressure dropped around 300 psi and flow expansion occurred followed by density cut. When this gas hit the choke, total back pressure reached 600 psi.

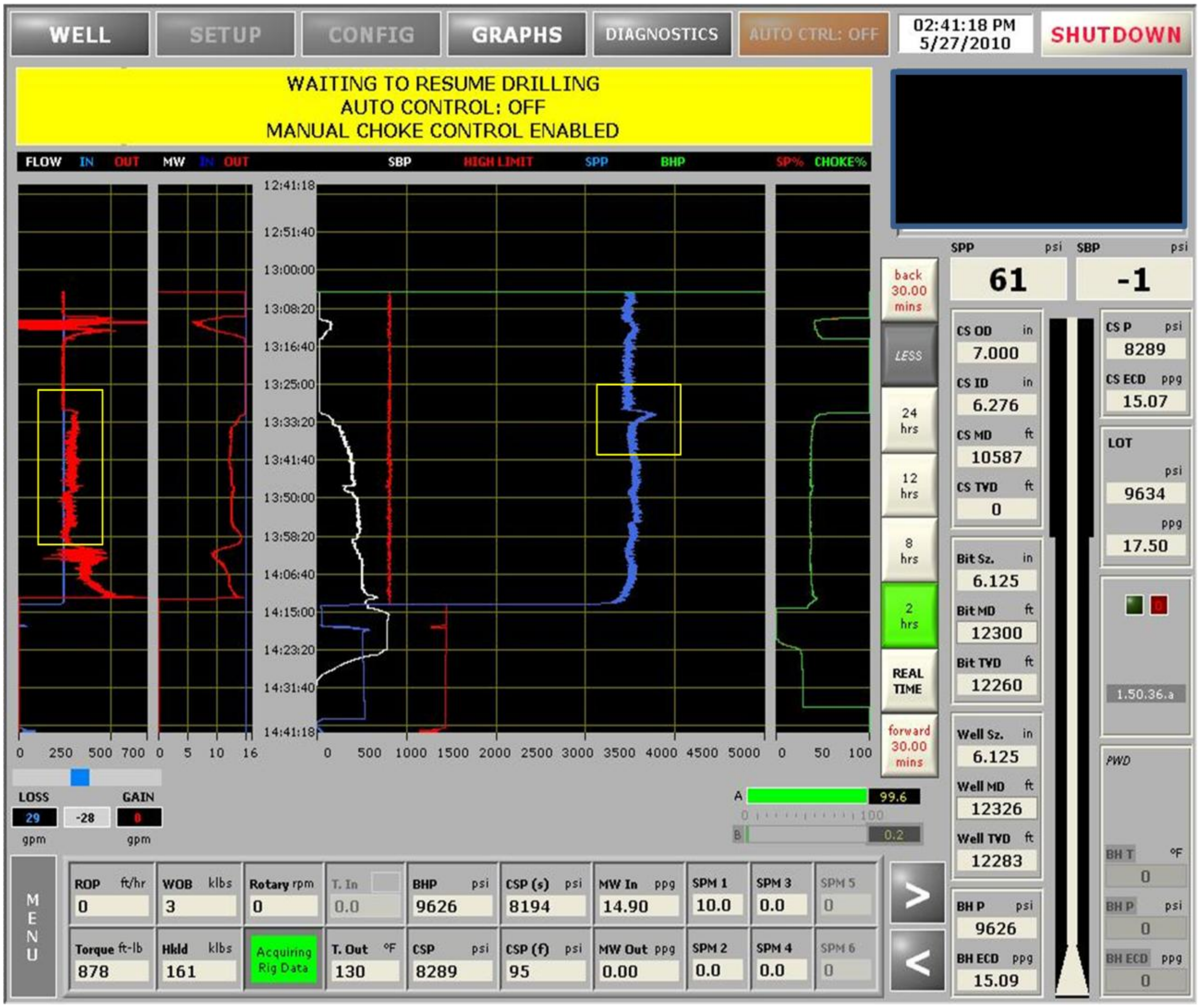


Figure 15: Kick event identification at 12326 ft MD.

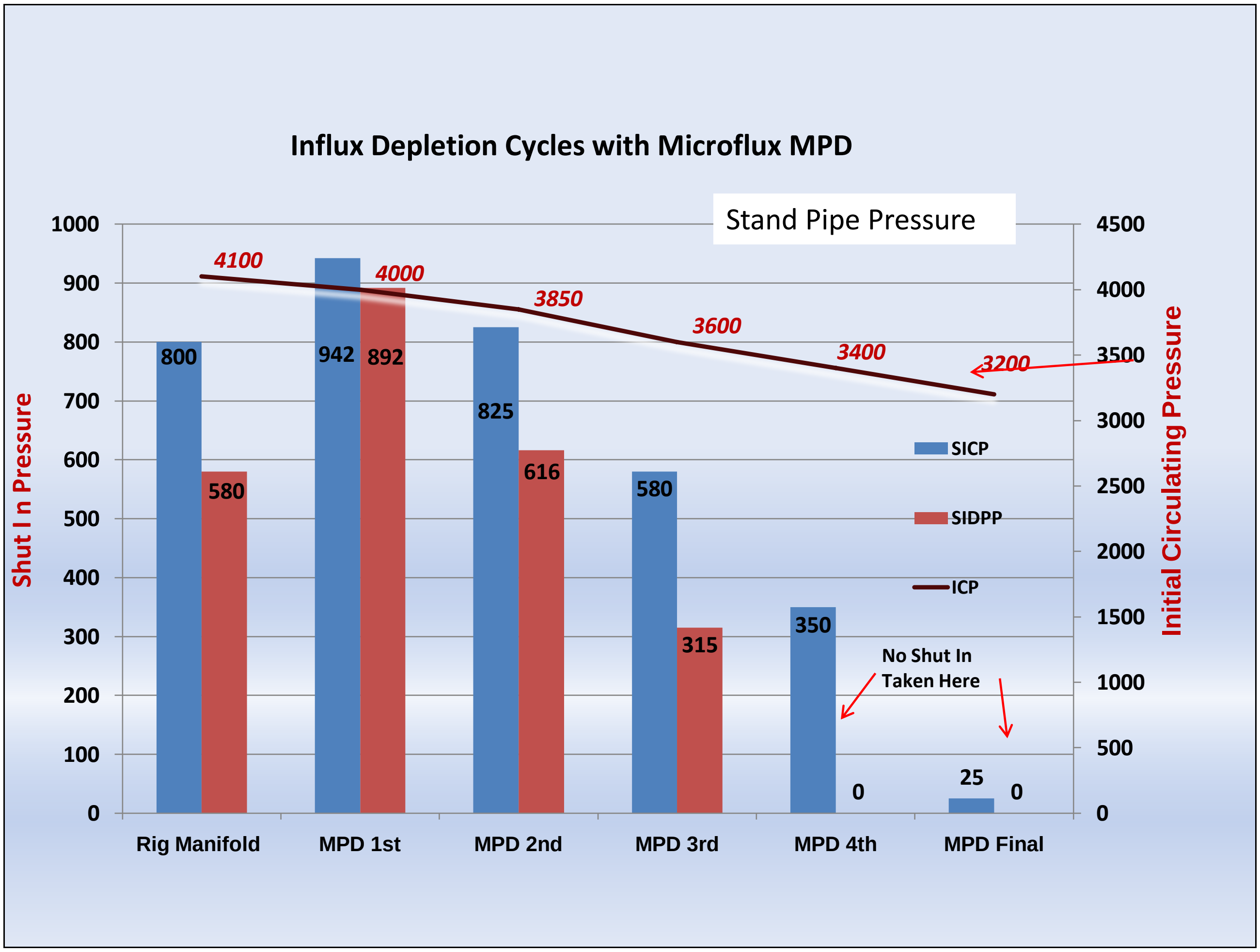


Figure 16: Depletion Cycles with MicroFlux MPD for Well B

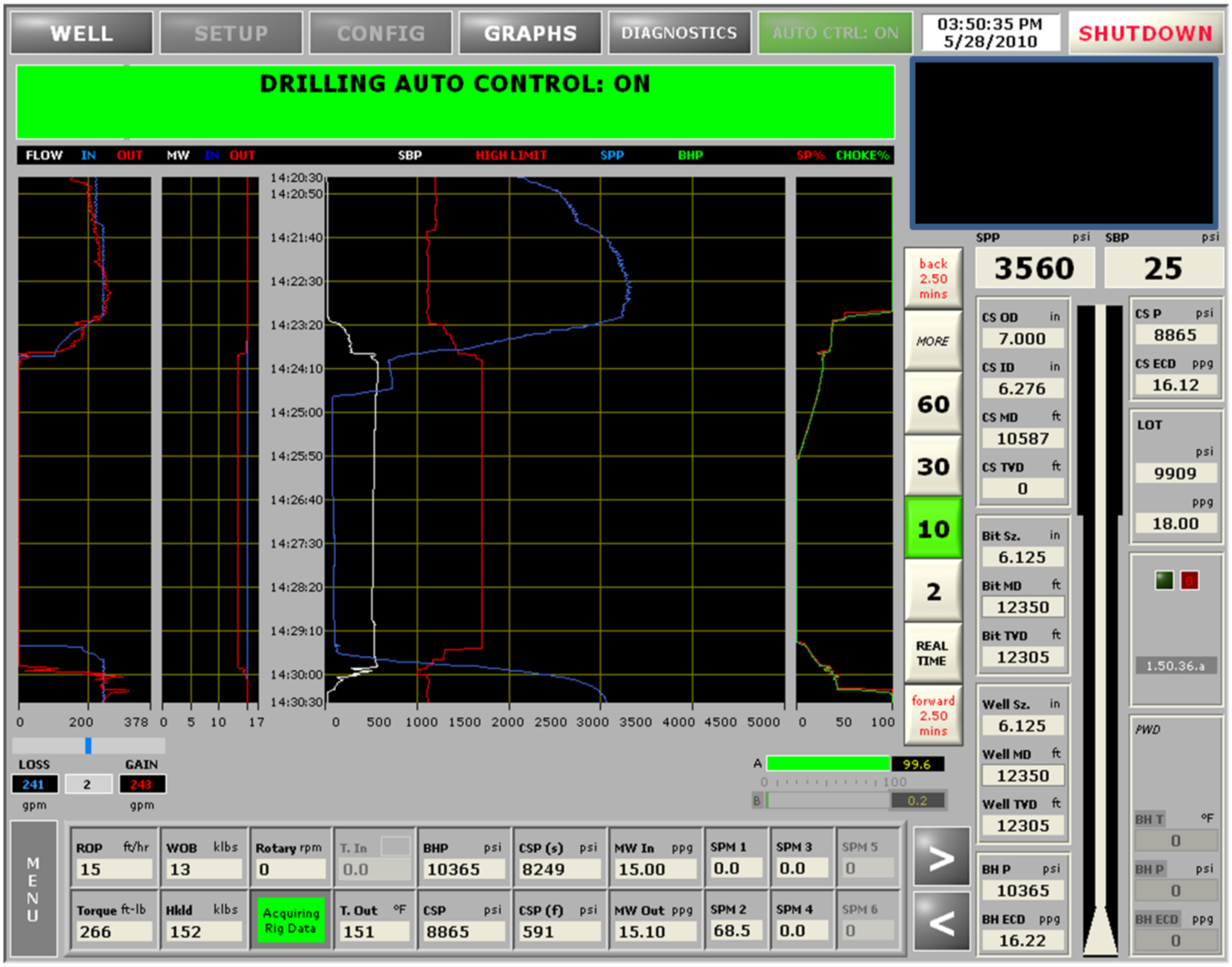


Figure 17: Holding 550 psi SBP during connection

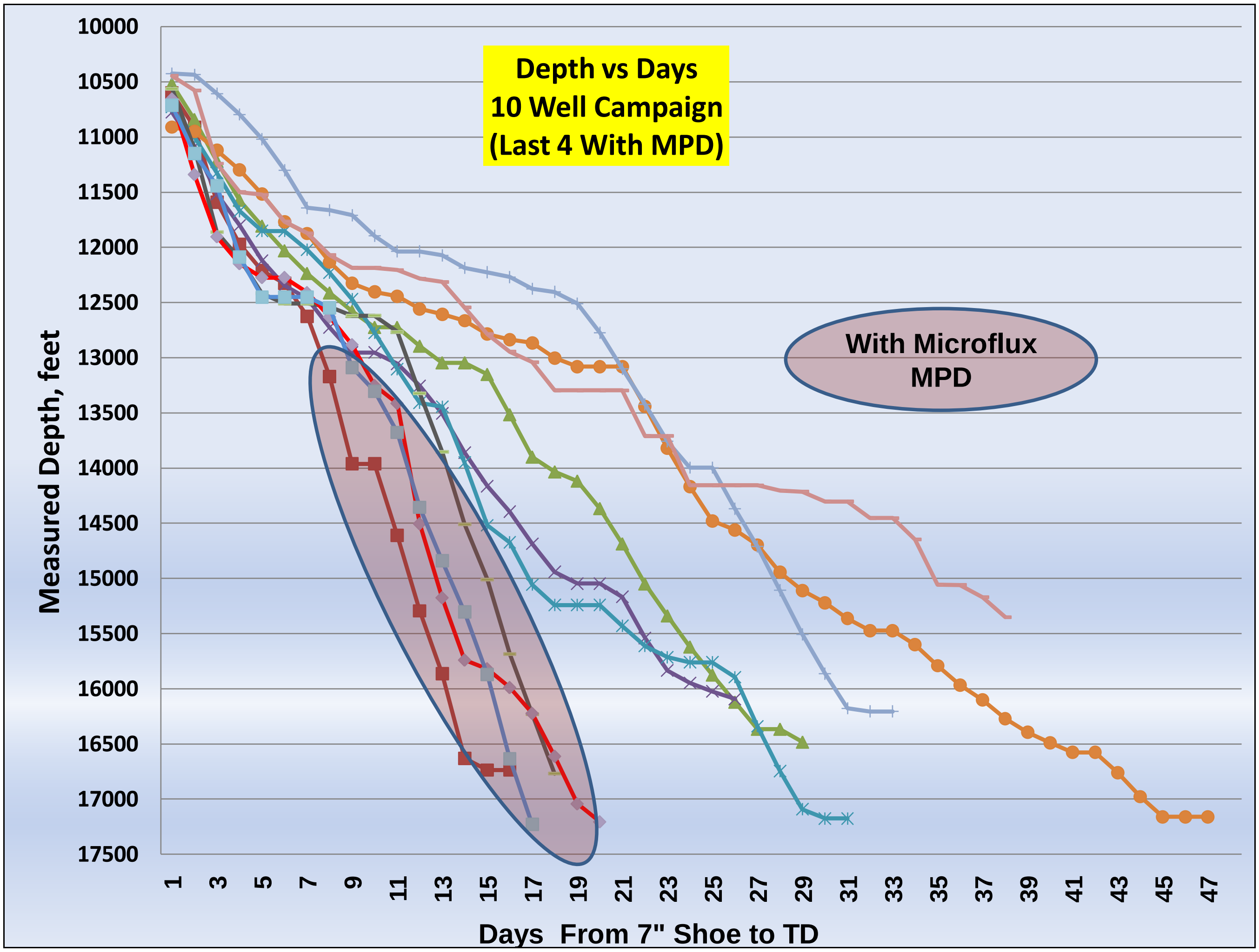


Figure 18: Drilling performance within the area, MPD wells versus conventional wells