STIMULATION TECHNIQUE HELPS PIN-POINT FRACTURES IN OPENHOLE HORIZONTAL SAN ANDRES WELLS

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ABSTRACT
The paper will discuss a stimulation technique performed on several openhole horizontal San Andres wells in Dawson and Gaines County, TX. Stimulation objectives will be outlined and explained along with supporting production information. The paper will also compare this completion technique with several other horizontal stimulation techniques performed in the recent history of this field.

RESERVOIR DESCRIPTION
The horizontals that are being studied in this paper are located in the Texas counties, Dawson and Gaines. The areas are denoted by specific units, the West Welch Unit (WWU) in Dawson and the Cedar Lake Unit (CLU) in Gaines County. The specific formation in which the horizontals are drilled in is the San Andres formation. Table 1 shows the typical reservoir parameters associated with the San Andres formation in each respective unit. The lithology can best be described as microcrystalline dolomite cemented fossil fragments with scattered amounts of anhydrite. Laboratory analysis of several core samples indicate the mineral composition ranging from 80-100% dolomite and 20-0% anhydrite. Acid solubility ranged from 85% to 93%. Permeability of each unit ranged from 1 md to 10 md; however, the Kv/Kh ratio is low at 0.01. It is also believed that a producing oil water contact (POWC) is prevalent in each field.

HORIZONTAL STIMULATIONS IN 2000
In 2000, four San Andres horizontal wells were drilled from existing vertical wellbores in the West Welch Unit. Located in Table 2 is a list of these wells with the horizontal length of each well, the hole size, and also the direction. As illustrated in Map 1, three of the wells were drilled in a north/south direction and the remaining well was drilled in a northeast/southwest direction. Each horizontal was stimulated a minimum of one time with most receiving a second stimulation treatment within 6 months of the first treatment.

WWU 705 is an openhole, 4 ¾-in. horizontal that was initially stimulated using coiled tubing. The coiled tubing was cycled along the entire open hole while pumping acid and nitrogen in an effort to "wash" the formation face. After 2 months of production, the horizontal was stimulated again using 10 slotted, ported subs, a large volume of acid, and rock salt as diverter.

WWU 1404 is an openhole, 4 ¾-in. horizontal that was stimulated using an acid hydra-jetting technique. Seventeen areas in the horizontal were stimulated (approximately one every 125 ft) with acid. After 5 months, the horizontal was stimulated again using a treating string with eight perforated subs uniformly distributed along the lateral and a highly viscous annular fluid system ("chemical packer").

WWU 4853 is an openhole, 4 ¾-in. horizontal that was stimulated using a hydra-jetting fracturing technique. Seven areas in the horizontal were stimulated using a crosslinked borate gel system and 20/40 mesh proppant.

WWU 4951 is a 4 ½-in. liner cemented inside a 6 ¾-in. open hole. The liner was perforated at 14 different intervals and stimulated using a cup-type packer deployed on coiled tubing. Each set of perforations were treated individually at 5 bbl/min.

2000 HORIZONTAL PRODUCTION SUMMARY

Production results for all four wells can be found in Table 4. The total production from WWU 705 was low after both stimulations. Due to the low production response, it was felt that neither the coiled tubing acid wash nor the slotted stimulation treatments was able to create fractures with conductive paths to the wellbore thus limiting production. The production responses from WWU 1404, WWU 4853, and WWU 4951 were higher; however, oil production was still below expectations. The focused stimulation approach on these last three wells did result in better performance, but it is believed that conductive fractures may not have been generated consistently along the lateral to create the desired effect throughout the length of the lateral.

2004 STIMULATION DESIGN CRITERIA

In 2004, two San Andres horizontal wells were drilled in the West Welch Unit and two San Andres horizontal wells were drilled in the Cedar Lake Unit. All four laterals were from existing vertical wellbores. Located in Table 2 is a list of these wells with the horizontal length of the each well, the hole size, and also the direction of each horizontal. As illustrated in Map 2 and Map 3, each was drilled in an east/west direction. From experience stimulating the four horizontal lateral wells in 2000, the stimulation design premise is that the formation needs to be hydraulically fractured to get the desired production response.

To achieve hydraulic fractures at predetermined points in a horizontal, some type of annular isolation must be present. The cemented liner would probably give the best annular isolation; however, in most re-entry opportunities running a cemented liner is not an economic option. The hydra-jetting fracturing technique appeared to have some success; however, operational success depends on the mechanical integrity of the production casing. In many cases, the re-entry wellbores have old casing (20 to 50+ years old) and this type of fracturing technique applied too much working pressure to the production casing than what the operator was willing to risk.

The technique of utilizing a chemical packer for annular isolation was the best option remaining, but the perforated subs had some operational flaws and hydraulic horsepower concerns. Operationally, the chemical packer was displaced by a wiper plug then followed by HCl acid. Over time, the chemical packer would set up and the acid would dissolve and open the perforated subs. On several occasions, this plug would get lodged part way down the string and thus all the ports would not open. On another occasion, the acid became contaminated and one of the perforated subs did not open. The hydraulic horsepower for these type jobs are relatively high due to the limited entry design and the need to fracture all the intervals at the same time. Cost associated with increased HHp can cause substantial increases in the stimulation cost.

INNOVATIVE STIMULATION TECHNIQUE

A new technique of pin-pointing the fractures presented itself in the form of ball-actuated sliding sleeves. The sliding sleeves would replace the perforated subs in the treating string. Also, the need for dropping a wiper plug and spotting acid behind the chemical packer was eliminated. The treating tubing is run in the horizontal wellbore placing the sliding sleeves across from intervals where a hydraulic frac is desired. Once the tubing string with the sleeves is in place, the chemical packer would be spotted in the annulus and allowed to set up. The first frac is then generated across from the end of the tubing string at the toe of the horizontal. To move to the second fracture point, a ball (designed for the first sleeve) would be dropped. The ball will land in the first sleeve and open a port to the annulus. The ball would act as a seal from allowing fluid to flow further down the tubing string. The process would be repeated for each remaining sleeve. By treating each sleeve location individually, the pump rate could be lower than with multi-zone fracturing techniques, reducing the hydraulic horsepower needed, and reducing the overall cost of the job.

FRACTURE DESIGN

Each fracture along the horizontal was designed for a specific length, height, and conductivity. The fracture height needed was determined by the proximity of the sliding sleeve to the producing oil water contact (POWC). Table 3 lists the range of fracture heights needed in each horizontal. A 3-D fracture modeling simulator was used to determine the rate and volume needed to be pumped to achieve each desired height. The pump rates were also adjusted at each fracture point in accordance with the position of the producing oil/water contact and the relative fracture height that was going to be generated.

The ideal fracture length was dictated by the horizontal length and number of fractures that could be placed in the horizontal in one day. Due to a size limitation of the ball actuated sliding sleeves and the tubulars, the number of treatment points was limited to seven. Once again, a 3-D design simulator was used determined the rate and volume that would yield the desired frac half-length. The ideal fracture half-lengths for each horizontal well are in Table 3.

The fracture conductivity needed was determined by using the formation permeability, estimated fracture length, and Walters & Byrd Production increase curves. While fracture half lengths in each horizontal were different, the permeability in each well was assumed to be the same in each field. From this analysis, the fracture conductivity needed was normally between 2000 md/ft and 6000 md/ft. It was felt that the designed fracture geometry was conservative compared to the geometry witnessed in the year-2000 horizontal program.

FLUID DESIGN

On the Cedar Lake Horizontal frac treatments, gelled acid was pumped first to generate the fracture dimensions needed and secondly to address leakoff associated with acid fracturing. Heated acid was then pumped to increase the reaction rate and thus yield better conductivity in the fracture. The acid volumes were also selected to achieve a desired contact time of 25 to 30 minutes. Acid fracture conductivity tests were conducted on core samples from several wells in the field in the early 1980's. The testing showed a substantial increase in conductivity with an increase in acid contact time. Due to the proximity of the POWC, gelled acid with its slower reaction time was not pumped on the West Welch wells.

DESIGN EXAMPLE

In WWU 3706, the ideal fracture half-length needed was approximately 184 ft due to the horizontal length and sliding sleeve limitations. The fracture conductivity needed was then determined by using the Walters & Byrd Production increase curves (See Graph 1). At 184 ft, the average conductivity needed would be between 2,000 and 5,000 md-ft. The third dimension of the each fracture was the fracture height. The POWC remained 26 ft below the horizontal for the entire length of the lateral. A 3-D design simulator was run to determine the best rate and volume to achieve these criteria. A pump rate of 5 bbl/min was used even though the downward height growth indicated that it would penetrate the POWC (See Table 3a). Keeping the contact time in mind, the acid volume was set at 6000 gallons. The estimated conductivity and length of the fracture can be seen in Graph 2.

Generating a fracture with the exact dimensions set forth above would be unlikely; however, achieving something close was possible. The fracture designed for WWU 3706 had a downward height of 35 ft, a conductive fracture half length of 158 ft, and an average conductivity of 3,070 md-ft.

2004 PRODUCTION SUMMARY

Production results for all four wells are in the Table 5. All four laterals resulted in increased production over its production as a vertical well. The production response in WWU 3706 has been lower than expected. The low production rate has been attributed to a conservative fracture design and low flood injection support. Because of the proximity of the POWC, the pump rate on the fracture treatment was held at 5 bbl/min. The production response from WWU 3920 has been much better even though the stimulation design was similar. It is uncertain as to why WWU 3920 is significantly better than WWU 3706; it may be a more effective stimulation treatment, higher reserve target, and may have better flood injection support.

The production results from Cedar Lake were expected to be better than in the WWU wells due to better reservoir quality and banked reserves from secondary recovery. CLU 359 has shown high fluid production and continues to maintain high fluid levels. CLU 446 initially produced total volumes similar to CLU 359; however, the decline rate has been much higher. Scaling issues and possibly swept reserves may be reasons why production in CLU 446 is less.

CONCLUSIONS

Because of the low ratio of vertical permeability to horizontal permeability, generating hydraulic fracs in the horizontal wellbores are essential at both Cedar Lake and West Welch Units. While concrete evidence of annular isolation is not present, the chemical packer appears to be the most practical and economical choice. The innovative design of the ball-actuated sliding sleeves in the treating string has proven to eliminate the many earlier operational pitfalls. The ball actuated sliding sleeves have also allowed the fracture design to use less HHp resulting in lower overall job costs. While designing the optimum frac treatment remains an ongoing learning process, both the design process and job execution have improved from the year-2000 program to the 2004 program.

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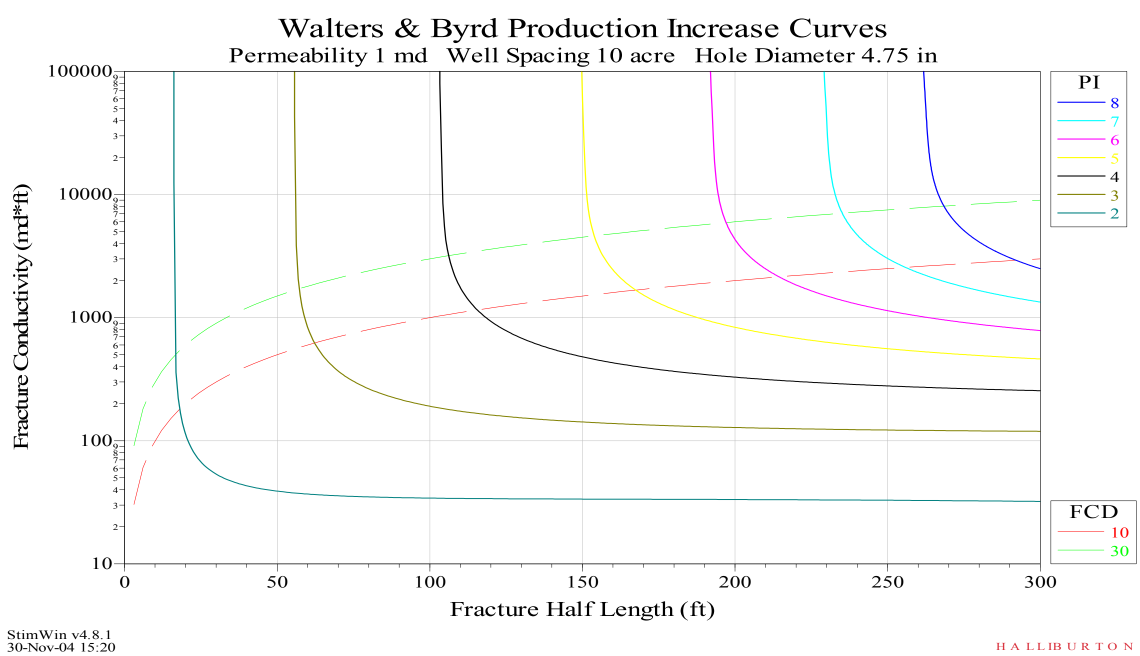
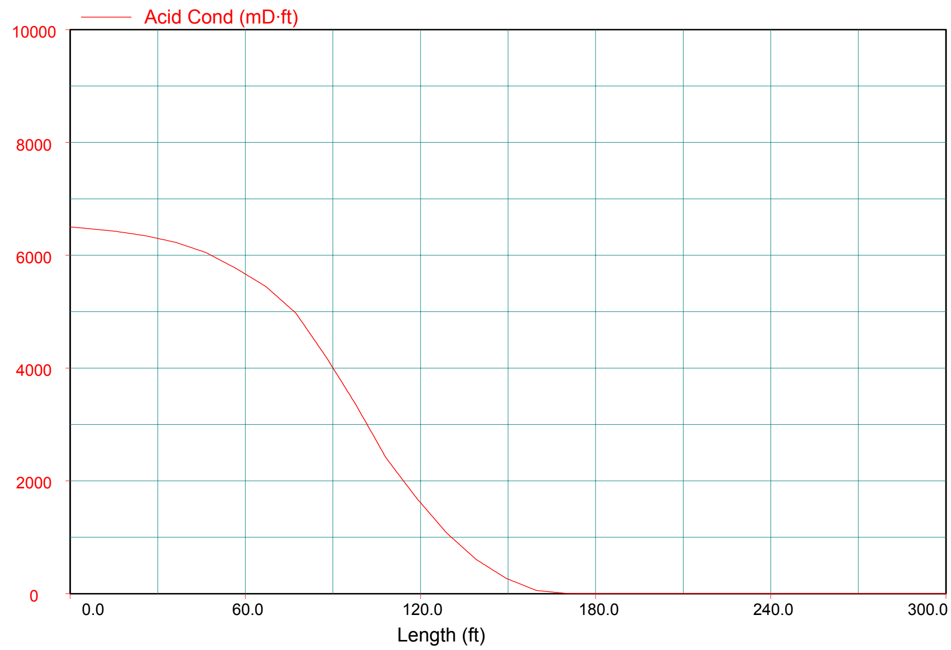


Graph 1 - Walters & Byrd Production Increase Curves

6000 gals Acid @ 5bpm



Frac Length

Graph 2 - Frac Length vs. Conductivity

Table 1
Reservoir Parameters

Cedar Lake Unit	
Pay Horizon:	San Andres
Lithology:	Dolomite
Structure:	Anticline
Trap Type:	Structural and Stratigraphic
Measured Depth:	4900 ft
Gross Pay Interval:	250 ft
Net Pay Interval:	100 ft
Porosity:	12-14%
Initial Water Saturation:	28%
Permeability:	3-10 md
Initial Reservoir Pressure:	1950
Reservoir Temperature:	96°F
West Welch Unit	
Pay Horizon:	San Andres
Lithology:	Dolomite
Structure:	Anticline
Trap Type:	Structural and Stratigraphic
Measured Depth:	4900 ft
Gross Pay Interval:	125 ft

Net Pay Interval:	61 ft
Porosity:	9.50%
Initial Water Saturation:	31%
Permeability:	1 md
Initial Reservoir Pressure:	2100 psi
Reservoir Temperature:	92°F

Table 2
Horizontal Dimensions

Year	Well	Hole Size	Lateral Length	Direction
2000	WWU 705	4 3/4in OH	2100	NE/SW
2000	WWU 1404	4 3/4in OH	2150	North/South
2000	WWU 4853	4 3/4in OH	3500	North/South
2000	WWU 4951	4 1/2in cemented liner	3250	North/South
2004	WWU 3706	4 3/4in OH	2450	East/West
2004	WWU 3920	4 3/4in OH	2250	East/West
2004	CLU 359	4 3/4in OH	1850	East/West
2004	CLU 446	4 3/4in OH	1800	East/West

Table 3
Fracture Criteria

Well Name	Minimum Frac Height	Maximum Frac Height	Ideal Fracture 1/2 Length
CLU 359	30	50	120
CLU 446	30	50	133
WWU 3706	26	26	184
WWU 3920	15	33	164

Table 3a
Fracture Geometry for WWU 3706

Pump Rate (bpm)	Upward Height Growth (ft)	Downward Height Growth (ft)
4	33	33
5	35	35
6	37	37
7	40	40
8	42	42
9	44	44
10	45	45

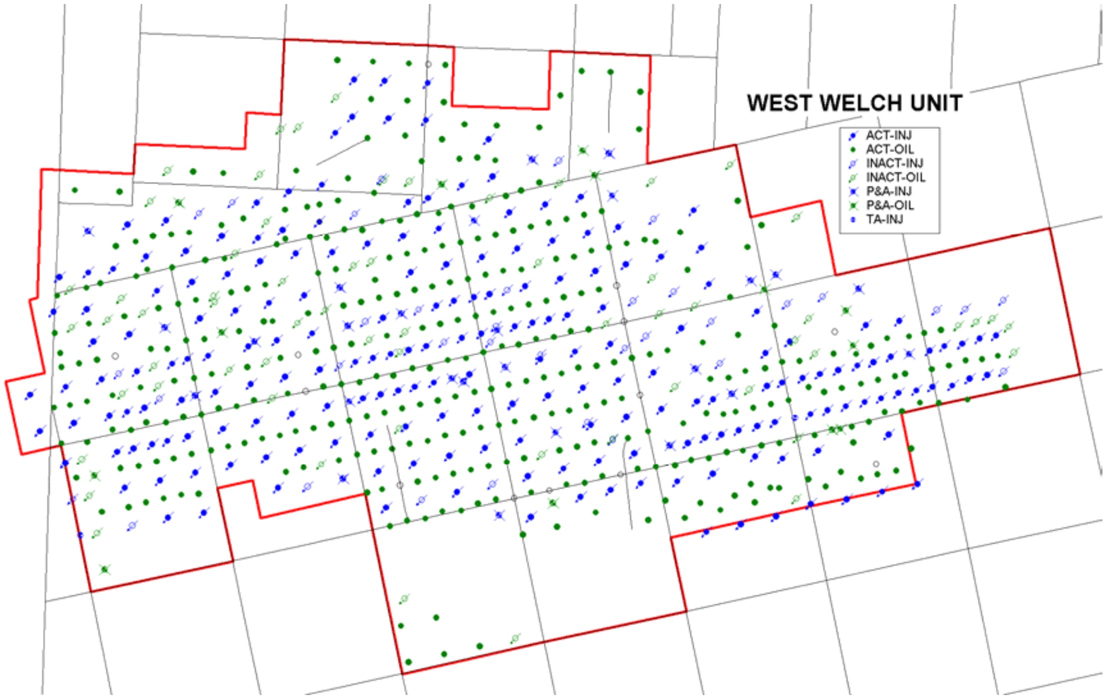
Table 4
2000 Horizontal Production (bbl/day)

Well	Vertical Well Oil	Vertical Well Water	Horizontal IP Oil	Horizontal IP Water	Horizontal 6mo Oil	Horizontal 6mo Water
WWU 705	5	50	48	33	30	16
WWU 1404	9	100	65	402	30	260
WWU 4853	3	10	41	610	9	87
WWU 4951	6	70	54	134	43	70
Average	**6**	**58**	**52**	**295**	**28**	**108**

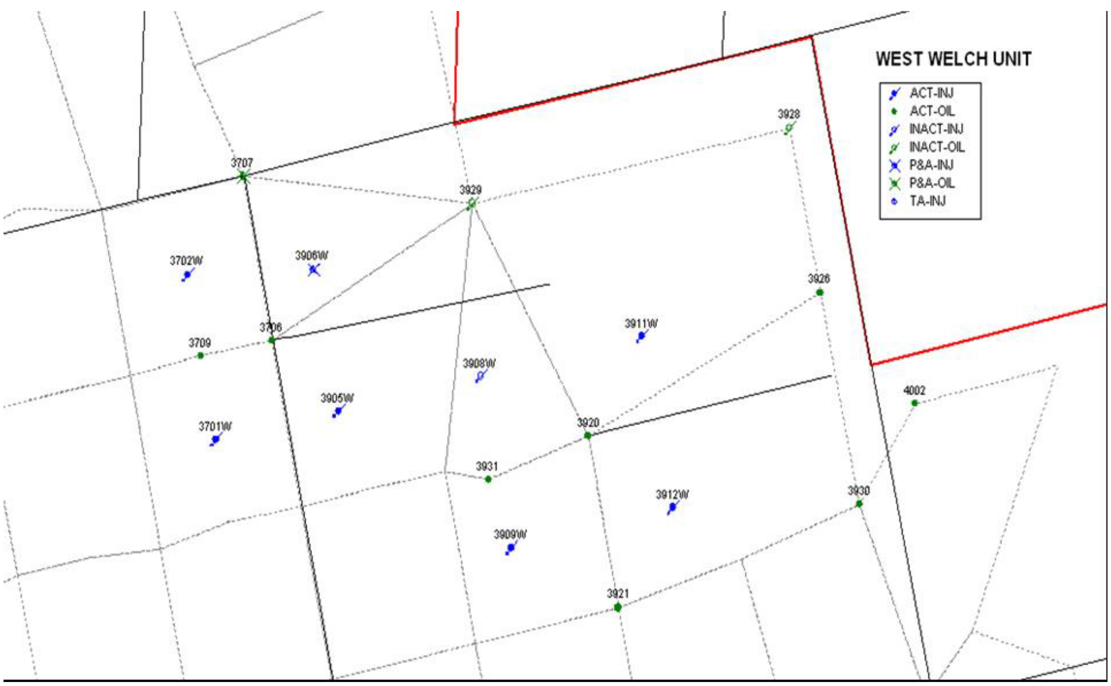
Table 5
2004 Horizontal Production (bbl/day)

Well	Vertical Well Oil	Vertical Well Water	Horizontal IP Oil	Horizontal IP Water	Horizontal 6mo Oil	Horizontal 6mo Water
WWU 3706	5	6	20	127	20	69
WWU 3920	14	17	245	235	66	36
Average	**10**	**12**	**133**	**181**	**43**	**53**

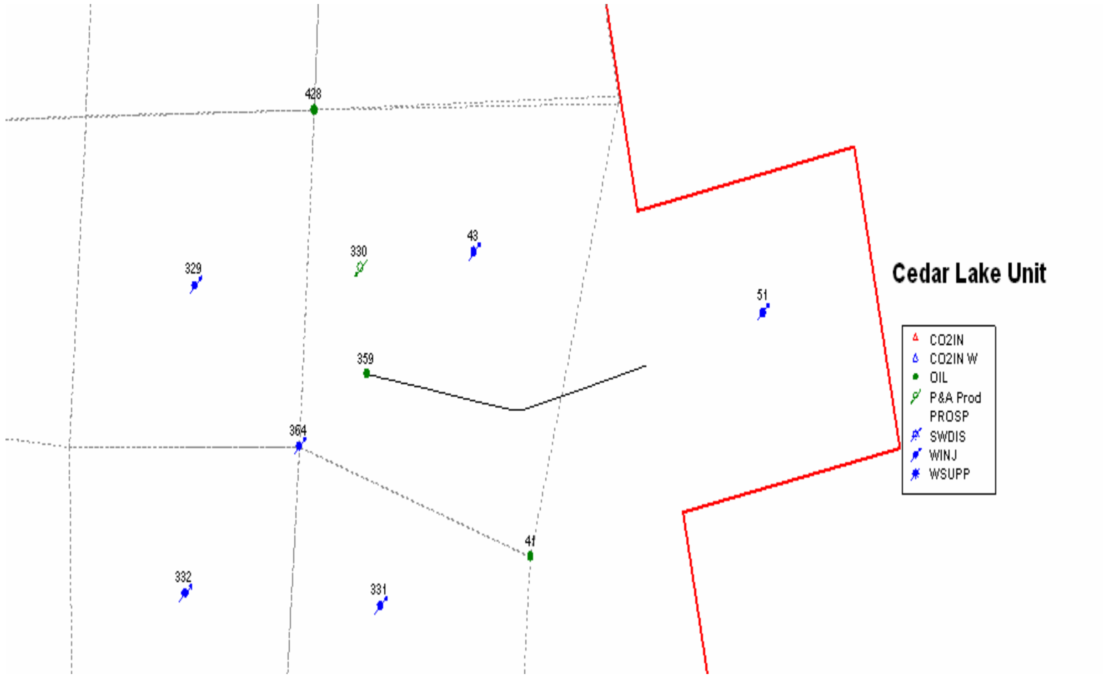
Well	Vertical Well Oil	Vertical Well Water	Horizontal IP Oil	Horizontal IP Water	Horizontal 6mo Oil	Horizontal 6mo Water
CLU 359	10	135	107	547	67	616
CLU 446	2	34	36	597	20	396
Average	**6**	**85**	**72**	**572**	**44**	**506**

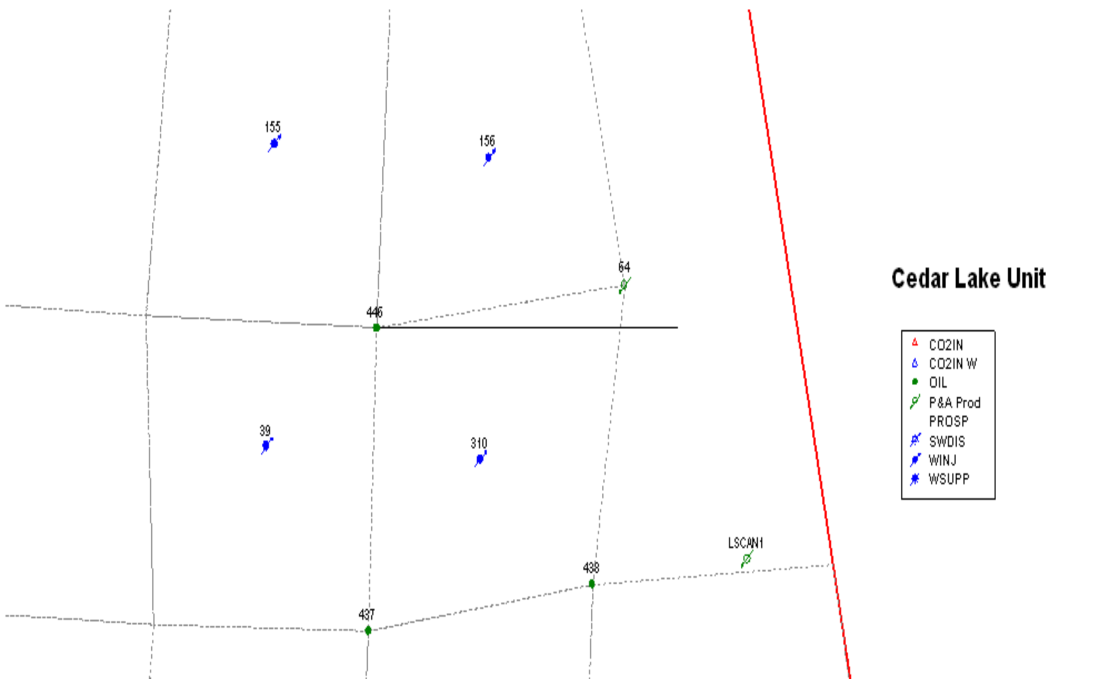


Map 1 - 2000 West Welch Horizontal Locations



Map 2 - 2004 West Welch Horizontal Locations





Map 3 - 2004 Cedar Lake Horizontal Locations