Exploitation and Optimization of Reservoir Performance in

Hunton Formation, Oklahoma

QUARTERLY TECHNICAL PROGRESS REPORT

Submitted by

Dr. Mohan Kelkar
Department of Petroleum Engineering
The University of Tulsa
600 S. College Avenue
Tulsa, Oklahoma 74104-3189

Contract Date: March 7, 2000

Completion Date: March 6, 2005

Reporting Period: July 1 – September 30, 2004

Date Issued: October 2004

DOE Contract No. DE-FC26-00NT15125

Prepared for

U.S. Department of Energy
Assistant Secretary for Fossil Energy

Contracting Officer's Representative:

Mr. Paul West
U.S. Department of Energy
National Petroleum Technology Office/DOE
Post Office Box 3628
Tulsa, Oklahoma 74103

Disclaimer

Abstract

West Carney field – one of the newest fields discovered in Oklahoma – exhibits many unique production characteristics. These characteristics include:

1) decreasing water-oil ratio;
2) decreasing gas-oil ratio followed by an increase;
3) poor prediction capability of the reserves based on the log data; and
4) low geological connectivity but high hydrodynamic connectivity.

The purpose of this investigation is to understand the principal mechanisms affecting the production, and propose methods by which we can extend the phenomenon to other fields with similar characteristics.

In our experimental investigation section, we present the data on surfactant injection in near well bore region. We demonstrate that by injecting the surfactant, the relative permeability of water could be decreased, and that of gas could be increased. This should result in improved gas recovery from the reservoir.

Our geological analysis of the reservoir develops the detailed stratigraphic description of the reservoir. Two new stratigraphic units, previously unrecognized, are identified. Additional lithofacies are recognized in new core descriptions.

Our engineering analysis has determined that well density is an important parameter in optimally producing Hunton reservoirs. It appears that 160 acre is an optimal spacing. The reservoir pressure appears to decline over time; however, recovery per well is only weakly influenced by the pressure. This indicates that additional opportunity to drill wells exists in relatively depleted fields. A simple material balance technique is developed to validate the recovery of gas, oil and water. This technique can be used to further extrapolate recoveries from other fields with similar field characteristics.

Table of Contents

Executive Summary

The analysis of production data from the West Carney field is continued in this quarter. Based on the analysis of the production data, the following observations can be reached:

- By injecting surfactant in reservoir cores, the wettability of the rock could be altered. By choosing an appropriate surfactant, gas relative permeability could be increased, whereas, the water relative permeability could be decreased. This effect should increase GWR, and hence reduce the lifting costs and increase the overall gas recovery.
- Two new stratigraphic units are identified based on geological analysis. These units further indicate geological complexity of the reservoir.
- The optimal well density for Hunton formation appears to be 160 acres. Additional potential exists to drill wells in the region with lower well densities.
- A simple material balance technique is able to explain most of the behavior observed in the field. This technique can be used to determine oil and gas recoveries from new fields yet to be produced.

Experimental

Kishore Mohanty, University of Houston

Objective

The objective of the second phase of this project is to study the effect of near well bore surfactant treatment on productivity enhancement. In water-wet gas reservoirs, water saturation is high in the near well bore region (or at fracture faces). This leads to low gas relative permeability and low productivity. Treatment of the near-well bore region by a surfactant solution can make the surface less hydrophilic and thus increase the gas-water contact angle. This can lead to a decrease in water saturation and an increase in gas flow. In gas condensate reservoirs, condensates (or oil) accumulate in the near well bore regions (and fracture faces). Making the surface neutral wet to both water and condensate can improve gas productivity.

Methodology

In this study, we have investigated the gas - water wettability in the absence of oil and the use of surfactant to enhance gas productivity by altering wettability. The laboratory studies were conducted in two scales. The first set of experiments was done on a surface scale, where carbonate surfaces (Calcite and Marble) were treated with surfactant solutions to study their effect on wettability. The second set of experiments is being conducted with carbonate cores to study the effect of surfactants on effective gas permeability. The second set of experiment is reported here.

Fluids Used. The surfactants used for this study are surfactants D and F. Synthetic brine of 0.1 N NaCl prepared in distilled water was used as the liquid phase. The specific gravity of the brine was 1.01. The temperature was at ambient conditions in the lab, which varied from 22^0C to 24^0C. Air was used as the gas phase.

Imbibition Studies. From studies at the slab-scale, two good surfactants, surfactants D and F, were chosen for further investigation on a larger scale. The following procedure was used to study the impact of wettability alteration in a core scale.

The carbonate cores were vacuum dried and then fully saturated with the synthetic brine (0.1 N NaCl). The brine permeability was measured. The cores were then flushed with humidified N_2 gas to a residual brine saturation at a pressure gradient of 10-14 psi/ft. The gas permeability at this residual saturation was measured.

The cores were then flooded from the opposite end with 6 PV of ethanol to remove any residual brine. The core was then flooded for 3 PV with surfactant solutions and aged in room temperature for a period of 24 hrs. The aged core was then again flooded with 6 PV of ethanol followed by 6 PV of synthetic brine to remove non-adsorbed surfactants and ethanol, respectively. The core was then flooded with humidified N_2 gas to a residual brine saturation at a pressure gradient of 10-14 psi/ft.

The core was then flooded with dry N_2 gas at a high pressure gradient of 100 psi/ft. It was then taken out of the core holder and immersed in brine. The spontaneous imbibition of brine was monitored. A reference core was also used to study brine imbibition without surfactant treatment. After the spontaneous imbibition the cores were flooded again with brine under vacuum to 100% brine saturation. They were then gas-flooded with humidified N_2 to residual brine saturation at a pressure gradient of 10-14 psi/ft to obtain the gas permeability at residual saturation. The pressure gradients were increased and their influence on water saturation and gas permeability were monitored.

Results and Discussion

Table 1 gives the physical properties of the carbonate cores used for imbibition studies. It also gives the values of relative permeability of gas at residual brine saturation before and after treatment along with the saturations. It can be seen that in the case of surfactant F, the residual brine saturation was altered considerably (~25%) and the gas relative permeability increased almost 160 times after treatment. Figure 1 shows a photograph of a brine drop on top of the core after treatment with surfactant F, indicating a change in wettability of the surface. The drop of brine does not imbibe spontaneously into the carbonate rock because of the intermediate wettability of the rock. In the case of surfactant D, the residual brine saturation decreased by ~10% and the gas relative permeability increased by a factor of ~30. These are significant, but lower than that of surfactant F. It was noticed that the surfactant F-treated core was intermediate-wet on both flat sides (from the drop experiment shown in Figure 1), but the surfactant D-treated core was intermediate-wet only on the surfactant injected flat side. There is a difference in the method of wettability alteration between the slab-scale and the core-scale experiments. In slab experiments, the slab was dried after the treatment. Whereas, in the case of core experiments, the cores were all flushed with ethanol and brine after the treatment of the surface. The core flushing sequence can be improved in the future to achieve better wettability alteration.

Table 1: Properties of the carbonate cores used for spontaneous imbibition.

Core	2	7	9
Surfactant	None	F	D
Permeability k (md)	120	117	119
Length(cm)	14.93	14.55	15.15
Diameter (cm)	3.82	3.82	3.82
Porosity	22.5	22.2	22.6
Residual brine saturation before treatment (%)	65	67.5	65
Gas permeability at residual saturation (md)	.21	0.13	.25
Residual brine saturation after Treatment (%)	-	42.5	56.25
Gas Permeability at Residual saturation (md)	-	20.5	7.97

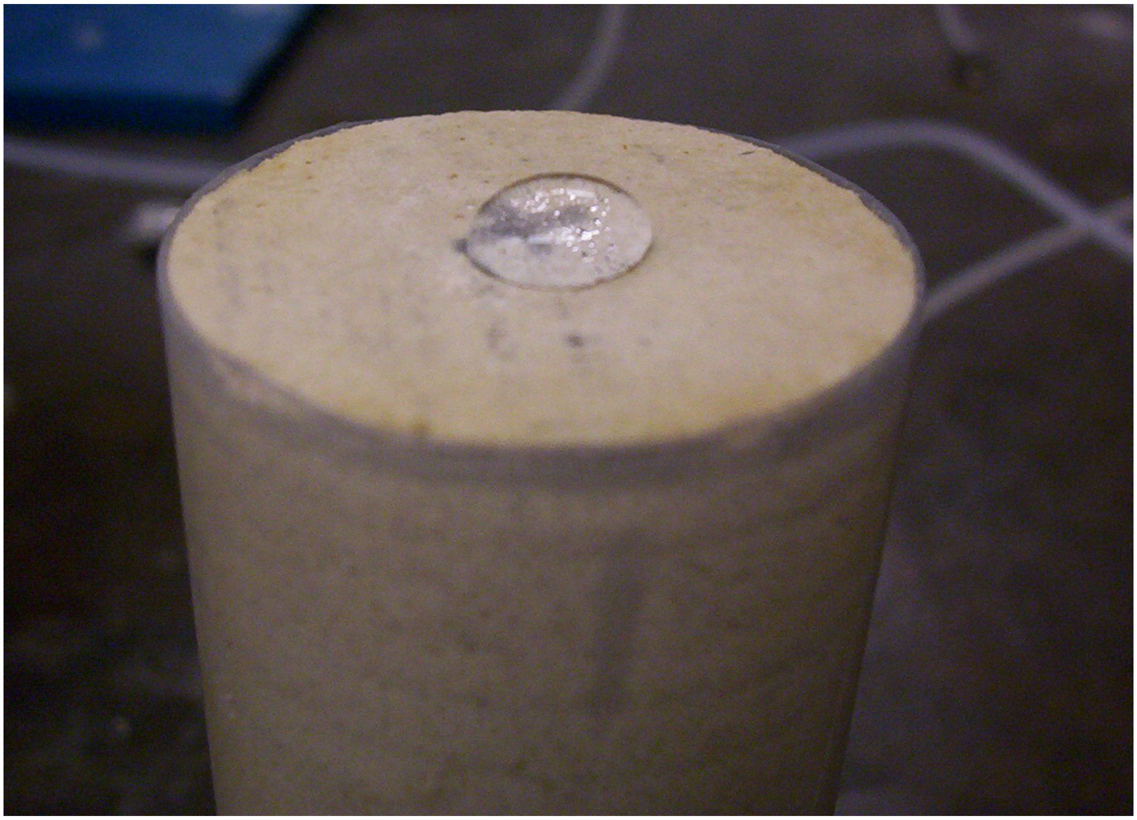

Figure 1: Photograph of the core after treatment with surfactant F, indicating change in wettability of the surface. The drop of brine does not imbibe spontaneously into the carbonate rock.

Figure 2 shows the amount of brine imbibed spontaneously as a function of time. The brine imbibition was 67.5 % OGIP (original gas in place) in about 20 hours for the untreated core. For the core treated with surfactant D, the brine imbibition was about 40% OGIP. For the core treated with surfactant F, it reduced to 7.5 % OGIP. Surfactant F succeeded in changing the wettability of the core and increasing gas permeability at residual brine.

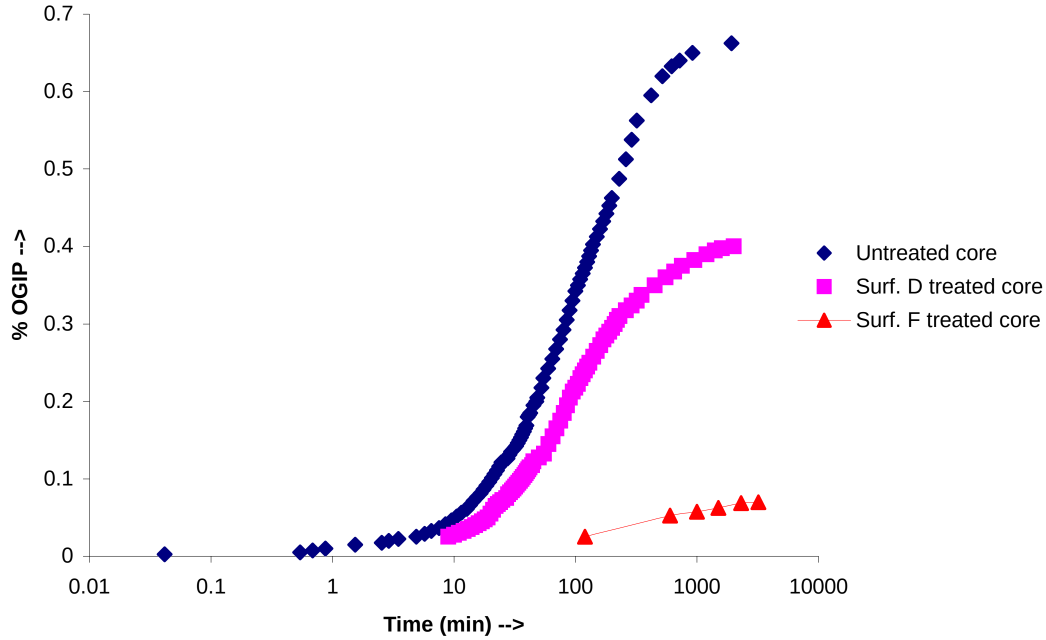

Figure 2: Spontaneous imbibition in carbonate cores at room temperature for case of untreated core, core treated with surfactant D and core treated with surfactant F, S_{wi} = 0%, and k = 120 md.

Two cores, one untreated and the other treated with surfactant F were then used to study the gas relative permeability at different residual water saturations. The cores were initially 100% water saturated. Then, they were gas flooded with humidified N_2 gas at different pressure drops. The pressure gradients used were 14 psi/ft, 32 psi/ft, 56 psi/ft, 120 psi/ft and 200 psi/ft. At each condition, the core was allowed to reach an equilibrium, which was noted by no additional production of water. The gas relative permeability was measured and the residual saturation was back calculated by monitoring the production of water. The results of the experiment are shown in Figure 3. It can be seen that for the same pressure gradient, the treated core showed a higher gas relative permeability than the untreated. For 200 psi/ft, the capillary number defined as $N_c = \frac{\Delta P\, k}{\sigma L}$ is $O(10^{-5})$. At this capillary number for gas as the wetting phase, the non-wetting phase (water) saturation starts decreasing with the increase of the capillary number. This could be the reason for the low saturation and high permeability at the highest pressure gradient for the treated core. Overall, the treated core gas permeabilities are higher than those of the untreated core at all pressure gradients.

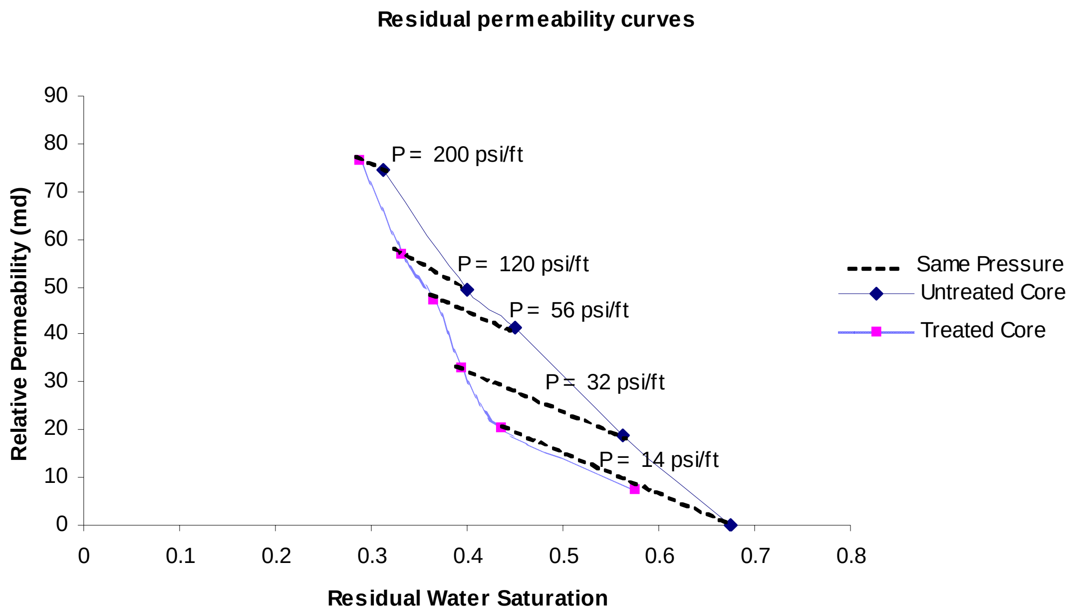

Figure 3: Residual permeability of gas for treated and untreated cores at different pressure drops across the core.

Conclusions

A surfactant has been identified which can change the air-water wettability of calcite and increase gas permeability at residual water saturation.

Results and Discussion

Geological Analysis

Jim Derby, Derby and Associates

Geological studies by James R. Derby & Associates for the last two quarters have been totally devoted to completion of description of cores, thin sections, lithologic facies and porosity types and compiling these data along with core analysis data for future reservoir characterization. This work is now completed, along with paleontological analysis of all cored wells to provide biostratigraphic control on formation and facies. Analysis of these data has just begun and will be the principal task during the last quarter of 2004. However a few general conclusions can be presented at this early time.

The six stratigraphic units previously recognized in the field (Figure 4) are now fully validated by paleontologic (conodont) studies on all 28 wells. An informal zonal terminology of "zones" 0 through 6 has been adopted for this study, rather than using the more proper, but cumbersome, faunal names for faunally defined time-stratigraphic units. (Figure 4). The paleontologic results are summarized on Figures 5 and 6. The upper part of the Clarita Fm (zone 6), known from outcrops in the Arbuckle Mountains has not been found in the field.

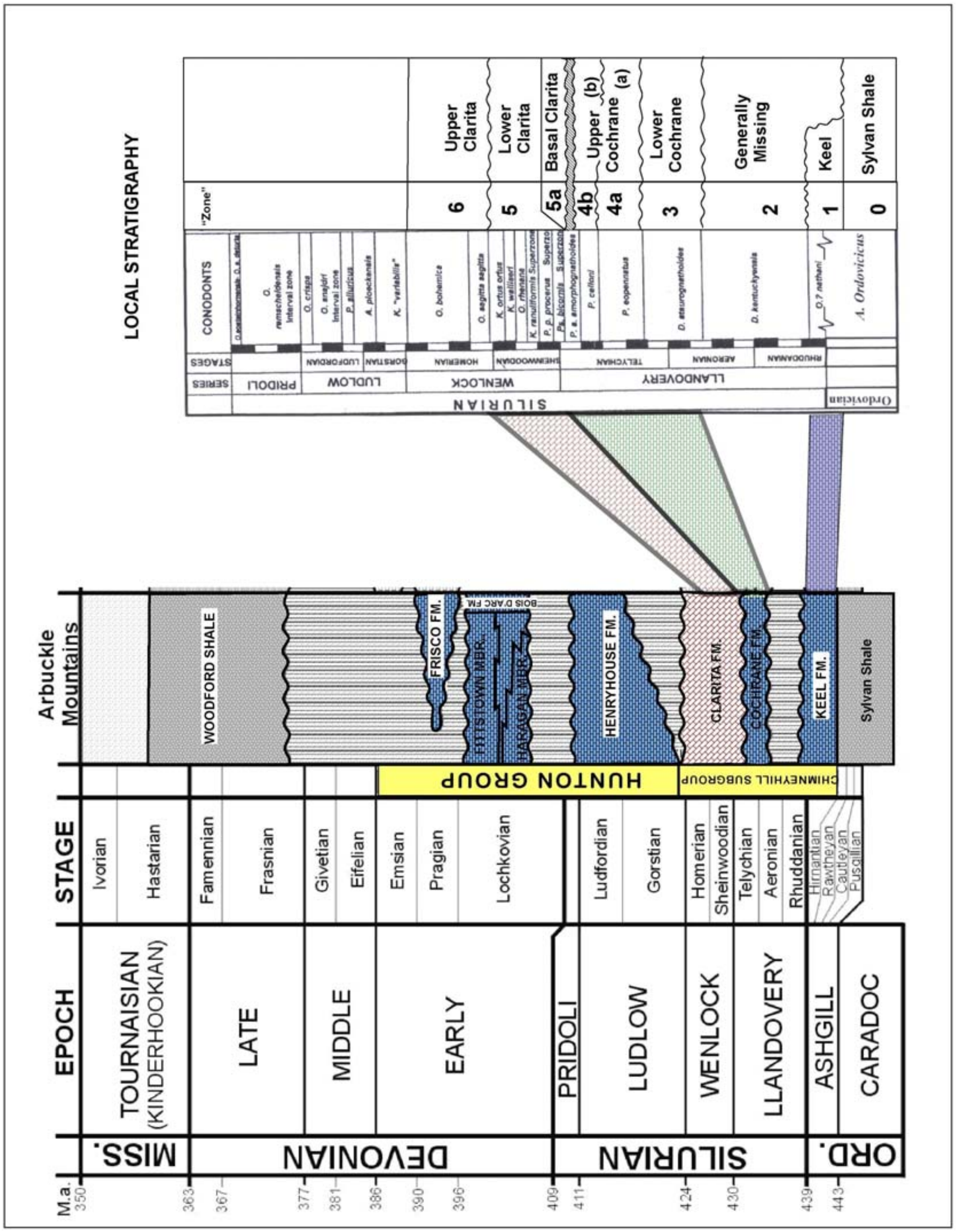

Figure 4: Stratigraphic Chart For Hunton Group, comparing Arbuckle Mountain Sequence (modified from Stanley, 2001, fig. 2), with WCHF sequence, by Barrick and Derby.

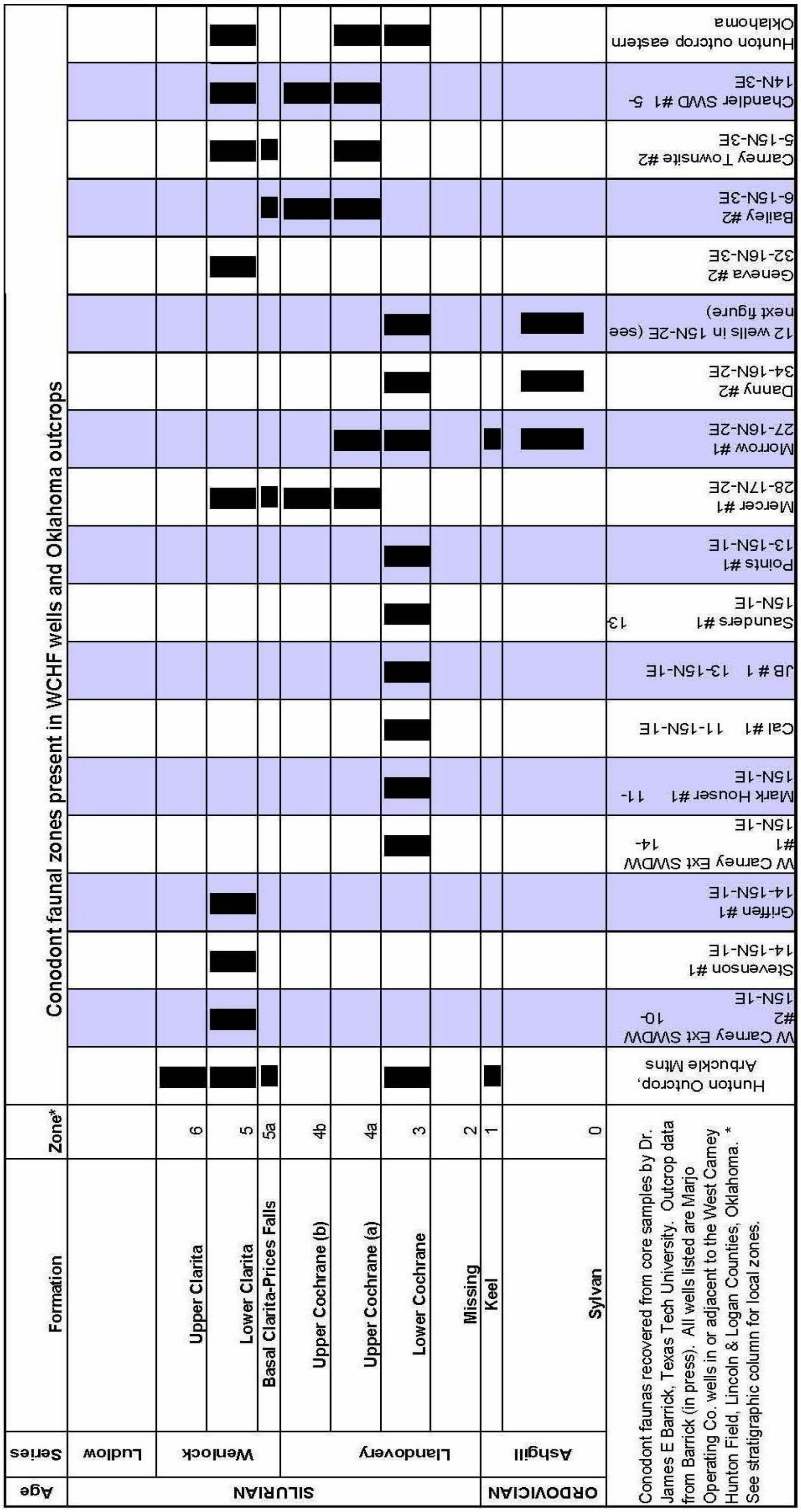

Figure 5: West Carney Hunton Field Paleontological Studies, showing faunal zones and formations identified paleontologically in each well. Also shown is faunal zones identified in outcropping formations in the Arbuckle Mountains, and in eastern Oklahoma.

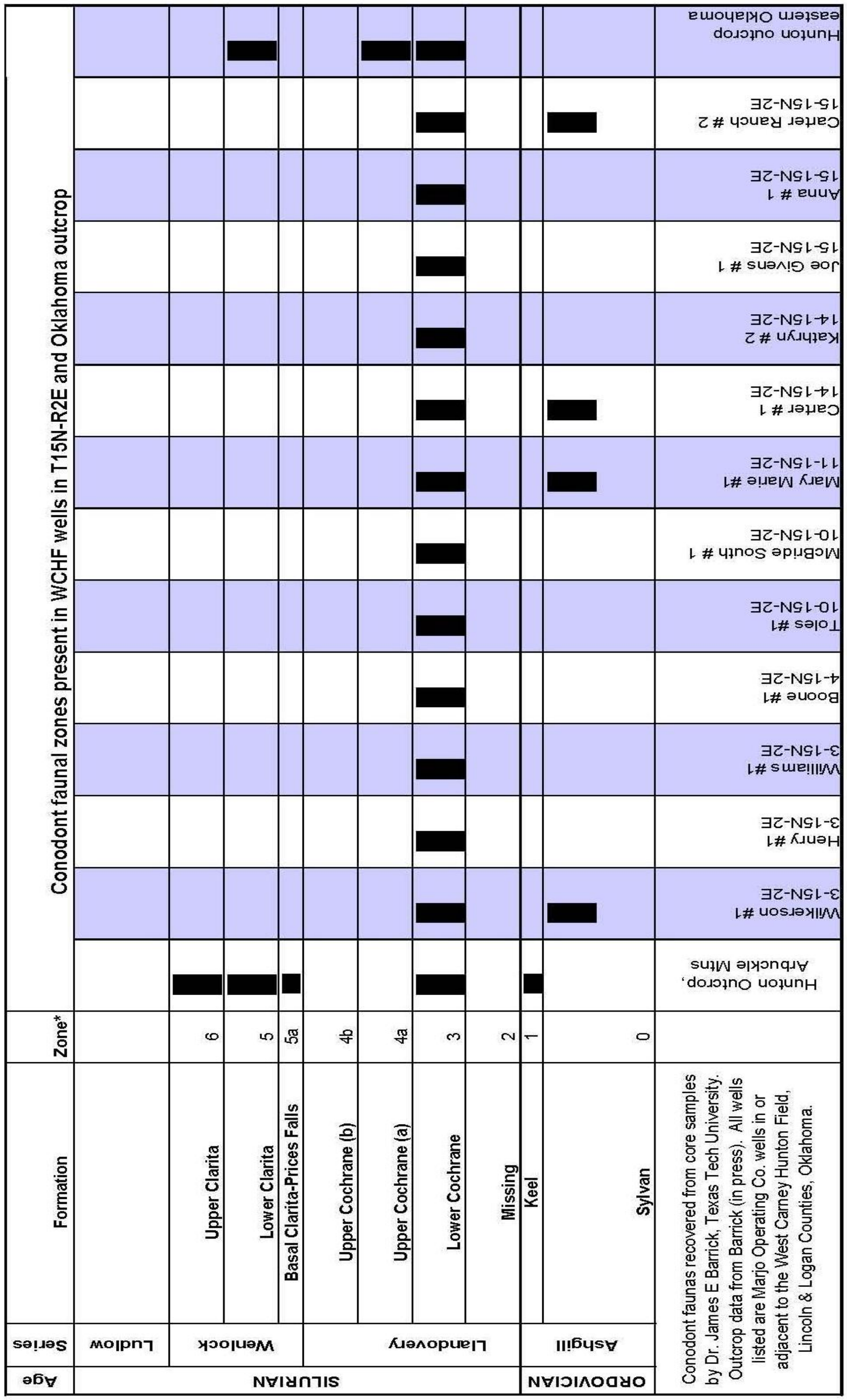

Figure 6: West Carney Hunton Field Paleontological Studies: T15N-R2E details, showing faunal zones and formations identified paleontologically in each of 12 Lower Cochrane wells in T15N-R2E. Also shown is faunal zones identified in outcropping formations in the Arbuckle Mountains, and in eastern Oklahoma

The Lower Clarita Fm. (zone 5) occurs in 7 wells, 3 on the west side of the field, 2 on the east, 1 north and 1 southeast of the field. The Quarry Mountain Formation., which crops out in eastern Oklahoma is apparently a lateral equivalent of the Lower Clarita in WCHF (Barrick, in press). The earlier conclusion, that the Clarita in the WCHF area is a shoal-water sediment deposited lateral to a high-standing island of older Hunton strata, appears supported by further evidence. The Basal Clarita (zone 5a) (apparently equivalent to the Prices Falls member of the outcrop and some subsurface areas) is found only in three wells, the Mercer, Bailey, and Carney Townsite.

The Cochrane formation is subdivided faunally into 3 distinct units, from youngest to oldest: the Upper Cochrane B (zone 4b), the Upper Cochrane A (zone 4b), and the Lower Cochrane (zone 3). The Upper Cochrane units are not present in the Arbuckle Mountain, outcrops. The fauna of the Upper Cochrane B has been recognized in 3 wells in WCHF and elsewhere in the southern Mid-Continent only in a well in Gray County, Texas (Amsden and Barrick, 1993). The Upper Cochrane A is present in 5 wells in WCHF and probably is the equivalent of the Tenkiller Fm. of the eastern Oklahoma outcrop (Barrick, in press). The Lower Cochrane is present in 20 wells cored by Marjo in WCHF, and is the equivalent of the Blackgum Fm. of the eastern Oklahoma outcrop. The three divisions of the Cochrane are present in both deep and shallow water facies, as determined by both by conodont faunal characteristics and by overall lithology and faunal content. The flanks of the field have deep water facies, in part, and the central part of the field is dominated by shallow water facies.

The last quarter of core description work has revealed that the Lower Cochrane in wells in the southwest part of the field is dominated by stromatoporoid-coral reef facies. The reefs had strong topographic relief at the time of deposition as revealed by primary dips of 15 to 35 degrees in reef-flank debris flow beds in four wells in sections 13 & 14, T15N, R 1E, Logan Co. This area also contains the thickest sections of Lower Cochrane in the entire field, with total thickness up to 142 feet (Figure 7). Apparently the western margin of the field at the end of “Cochrane time” was a steep, reef-dominated, slope, as the Lower Cochrane passes laterally very abruptly into the much younger Clarita Formation along the western margin of the field. The area of thin Hunton in the center of the field (Figure 7) is apparently all Lower Cochrane (Figure 6) and is dominated by open shelf brachiopod and crinoid facies, with lesser admixtures of coral material. Possibly this area represents a reef lagoon facies on a reef platform, with deeper water lying to the north and south.

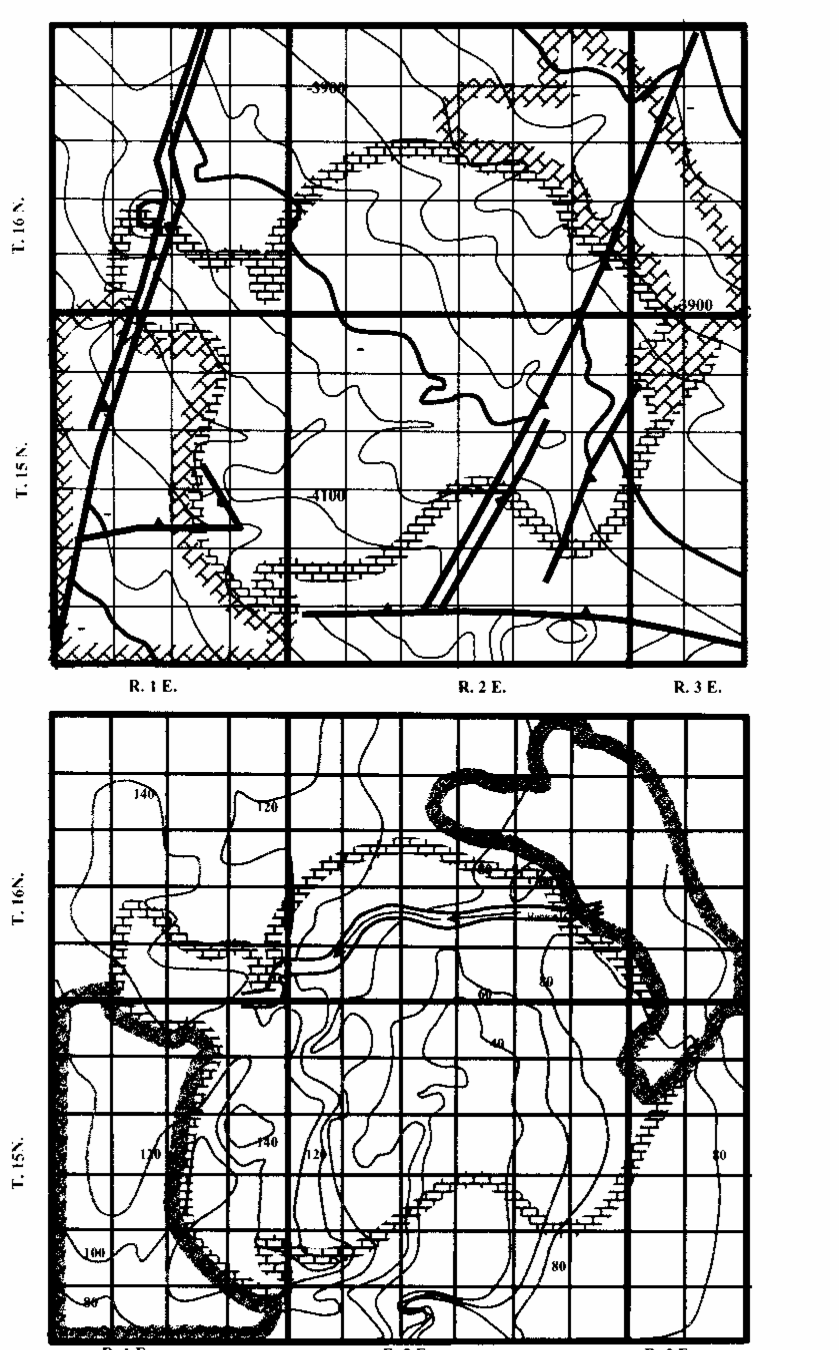

Figure 7: Thickness Isopach map of the Hunton Group in West Carney Hunton Field.

Summary of Data Presented

All cores in 28 wells in this project have been described, totaling 1510.9 feet of core, all 219 thin sections have been described, and 305 paleo samples from the 28 cores have been analyzed paleontologically. Table 2 lists all 28 wells listed alphabetically; Table 3 lists the 28 wells sorted by Range, Township, and Section. Also listed are formation tops and bases, interval cored, and the numbers of thin sections and paleo (conodont) samples taken on each well. The stratigraphy of the field resulting from this study is shown in the Stratigraphic Diagram, Figure 4. The zones and Formations paleontologically identified in each well are listed in Table 2 and 3, using the zone numbers shown in Figure 4. The zone and formation results from conodont studies are also shown graphically in Figures 5 and 6. Six divisions of the Hunton Group are recognized in the field. Two divisions of the Hunton, "Upper Cochrane A and Upper Cochrane B are new stratigraphic units, not previously recognized in Oklahoma. A brief summary of the lithology of each well is also given in Tables 2 and 3.

Table 2: List of wells cored by Marjo in West Carney Hunton Field and described in this study in alphabetic order.

			Hunton Top		Core log	Top LAS Log	Hunton Base		Thick-ness	Status & Data, * = Completed						
Well #	Well Name	Twp-Rng	Core	Log	Adj		Core	Log	Feet	Wk	TS	PC	SEM	Cono	Fm/zone	Lithology
All wells listed are Marjo Operating Co. Inc. wells																
5943	Anna 1 - 15	15-15N-2E	4967.1	4947.0	20.1	4928.0	5004.7	4985.0	37.6 cored	C	10*	C		9*	3	Dol
6011	Bailey 2-6	6-15N-3E	X(4876)	4875.0	-2.8		X(4934)	4964.0	58 cored; *89 log*	C	20*	C		25*	5a, 4b, 4a, ?3	14' Dol/Ls
5913	Boone 1-4	4-15N-2E	X (5037)	5028.0	6.5	5008.0	5066.5	5060.0	29.5+ cored 32 *log*	C	6*	C		6*	3	Ls/ dol Ls/ 4' dol
6088	Cal 1-11	NE_SE 11-15N-1E	X(5034)	5025.0	2.3		5135.8	5133.5	101.8 cored *108.5 log*	C	0*	C		21*	3	no pent br facies, Ls, off-reef, deep water at base
5992	Carney Townsite 2-5	5--15N-3E	X (4906)	4907.0	0.0		X (4966); *4978L;*	4978.0	60 cored; *71 log*	C	8*	C		16*	5, 5a, 4a	Dol/Ls
5934	Carter 1-14	14-15N-2E	X (4940)	4927.0	13.3	4917.0	4995.8	4983.0	56.1 cored *56 log*	C	16*	C		18*	3, 0	1'dol/ Ls/ 2'dol
6051	Carter Ranch 2-15	15-15N-2E	5006.0	5000.0	6.0		5035.1	5030.0	29.1 cored	C	5*	C		6*	3, 0	Ls/Dol
6281	Chandler SWDW # 1-5	5-14N-3E	X(4810)	4797.5	12.0		X(4869.8) *4877.5L*	4865.5	59.8 cored *68 log*	C	6*	C		14*	5, 4b, 4a	31' dol/28' shaly Ls
5838	Danny 2-34	34-16N-2E	X (4930)	4918.0	10.8	4898.0	4984.3	4973.5	54.3+ cored	C	2*	C		11*	3, 0	Ls
	Geneva 2-32 (not analyzed)	32-16N-3E	x(4889)	4873.0	15.0		x(4898.7) *4968ML*	4952.0 mudlogger	9.7 ft cored 64' by mudlogger	C	6*	NA		4*	5	Ls, Dol (Cri pkstn)
5874	Joe Givens 1-15	15-15N-2E	5017.8	5010.0	9.0	4990.0	5044.0	5035.0	26.2 cored	C	0*	C		4*	3	Ls/ 0.1' dol
6209	Griffen 1-14	NW-NW-SW 14-15N-1E	X (5082)	5077.0	5.0		X(5142); *5191.5L*	5186.5	60 cored *109.5 log*	C	6*	C		14*	5	Ls/dol/limy dol
5818	Henry 1-3	3-15N-2E	X (4966)	4958.0	7.5	4938.0	X (4996.6) *5004.5L*	4997.5	30.6+ cored	C	3*	C		4*	3	Ls/5' dol/ls
6100	Mark Houser 1-11	11-15N-!E	X(4961)	4940.0	12?		X(5077.6) *?5078L*	5066.0	116.6 cored *126 log*	C	6*	C		7*	3	Ls
6112	JB 1-13	13-15N-1E	4971.9	4966.0	5.9		X(5058.8) *5125.9L*	5120.0	86.9 cored *154 log*	C	2*	C		24*	3	Ls, reef-flank & reef
6029	Kathryn 2-14	14-15N-2E	X(4994)	4990.0	3.5		5030.5	5027.0	36.5 core *38 log*	C	4*	C		8*	3	Ls/Dol/Ls/Dol
5705	Mary Marie 1-11	11-15N-2E	4961.0	4944.0	17.0	4924.0	5003.5	4988.5	42.5 cored	C	33*	C	4	14*	3, 0	Ls/ 2'dol
5899	McBride South 1-10	10-15N-2E	X (4962)	4947.0	13.3	4927.0	4996.2	4983.0	34.3 cored *36 log*	C	1*	C		5*	3	Ls/dol/ls
6150	Mercer 1-28 *	28-17N-2E	X(4527)	4526.0	0 ?		X(4583) *4606L*	4606.0	56 cored *80 log*	C	5*	C		17*	5, 5a, 4b, 4a	16' Dol, 40' shaly Ls
6247	Morrow 1-27	27-16N-2E	X(4905)	4886.0	0.5		4956.5	4956.0	53 cored *69 log*	C	8*	C		15*	4a, 3, 1?, 0	Ls/5' dol, keel oolite
6143	Points 1-13	13-15N-1E	4989.5	4978.0	11.5		X(5107) *5107.5L*	5096.0	117.5 core *118 log*	C	6*	C		8*	3	2.5' Wfd, 60' big br, vuggy, 57'wkstn,
6131	Saunders 1-13	SE-NE 13-15N-1E	4917.3	4911.0	6.3		X(4940.5) *5059.3L*	5053.0	23.2 cored *142 log*	C	1*	C		4*	3	Ls, Pent Br, reef flank
6302	Stevenson 1-14	NW 14-15N-1E	X(5143)	5103.0	2.0		X(5167.6) *5188L*	5186.0	24.6 cored *83 log*	C	7*	C		7*	5	Ls/Dol
5733	Toles 1-10	10-15N-2E	4964.0	X	na	na	5003.8 *5005.0L*	X	39.8 cored	C	8*	C		5*	3	Ls/ 2'dol
6061	W Carney Ext SWDW #1	14-15N-1E	5042.7	5038.0	4.7		X(5131); *5156 L*	5151.0	88.7 cored *113 log*	C	15*	C		10*	3	Ls, reef-flank
6563	W Carney Ext SWDW # 2	10-15N-1E	X(5140)	5133.5	4.5		X(5232) *5275L*	5270.5	92 cored *137 log*	C	12*	C		13*	5	Dol & doltc is crinoid grnstn, shoal water facies
5712	Wilkerson 1-3	3-15N-2E	4953.4	4937.5	15.8	4917.0	4999.8	4984.0	46.4 cored	C	19*	C	1	11*	3, 0	Ls/ 2'dol
5887	Williams 1-3	3-15N-2E	4943.5	4934.0	9.5	4914.0	4983.7	4974.0	40.2 cored	C	4*	C		5*	3	Ls/ 5' dol
Totals									1510.9		219			305		

Wk = Work status (Core description), C = Completed; IP = In Process; PC = Porosity Codes.
TS = Thin Sections,# made, * described ; SEM = Scanning Electron Microscopy, Cono = Conodont micropaleontology, # of samples, * completed
UH = Core Plug samples at Univ. Houston; Wett = Wettability Analysis,
Hg Inj = Mercury injection porosimetry
Numbers in front of Well Name is StimLab well Identification Number

* Mercer not logged, but 75' offset (WFC Petroleum #1-28 Cruse) was logged (N-D, Sonic, Lateral logs - same thickness as Mercer, 80'),
Sandeep to digitize, Import digitized log data for Cruse 1-28 into Mercer 1-28.
Note re core depth: Columns "X ( ) " indicate core depth of top & base of core, when formation top or base is not cored.
Numbers in italics followed by L, indicates equivalent core depth of base of Hunton converted form log depth. ML = mud logger depth.

Table 3: List of wells cored by Marjo in West Carney Hunton Field and described in this study, sorted by Range, Township, and Section. Also showing the same data as in Table 2.

X = top or base of Hunton not cored;; (footage) = top or base of core; *italicized depth* is "core depth" of fm top or base picked on logs

						Hunton Top		Core log	Top LAS Log	Hunton Base		Thick-ness	Status & Data, * = Completed						
Well #	Well Name	Sec	Twp N	Range E	Twp-Rng	Core	Log	Adj		Core	Log	Feet	Wk	TS	PC	SEM	Cono	Fm/Zone	Lithology
	All wells listed are Marjo Operating Co. Inc. wells																		
6563	W Carney Ext SWDW # 2	10	15	1	10-15N-1E	X(5140)	5133.5	4.5		X(5232) *5275L*	5270.5	92 cored *137 log*	C	12*	C		13*	5	Dol & doltcls, crinoid grnstn, shoal water facies
6088	Cal 1-11	11	15	1	NE_SE 11-15N-1E	X(5034)	5025.0	2.3		5135.8	5133.5	101.8 cored *108.5 log*	C	0*	C		21*	3	no pent br facies, Ls, off-reef, deep water at base
6100	Mark Houser 1-11	11	15	1	11-15N-!E	X(4961)	4940.0	12?		X(5077.6) *?5078L*	5066.0	116.6 cored *126 log*	C	6*	C		7*	3	Ls
6112	JB 1-13	13	15	1	13-15N-1E	4971.9	4966.0	5.9		X(5058.8) *5125.9L*	5120.0	86.9 cored *154 log*	C	2*	C		24*	3	Ls, reef-flank & reef
6131	Saunders 1-13	13	15	1	SE-NE 13-15N-1E	4917.3	4911.0	6.3		X(4940.5) *5059.3L*	5053.0	23.2 cored *142 log*	C	1*	C		4*	3	Ls, Pent Br, reef flank
6143	Points 1-13	13	15	1	13-15N-1E	4989.5	4978.0	11.5		X(5107) *5107.5L*	5096.0	117.5 core *118 log*	C	6*	C		8*	3	2.5' Wfd, 60' big br, vuggy, 57'wkstn,
6061	W Carney Ext SWDW # 1	14	15	1	14-15N-1E	5042.7	5038.0	4.7		X(5131); *5156 L*	5151.0	88.7 cored *113 log*	C	15*	C		10*	3	Ls, reef-flank
6209	Griffen 1-14	14	15	1	NW-NW-SW 14-15N-1E	X (5082)	5077.0	5.0		X(5142); *5191.5L*	5186.5	60 cored *109.5 log*	C	6*	C		14*	5	Ls/dol/limy dol
6302	Stevenson 1-14	14	15	1	NW 14-15N-1E	X(5143)	5103.0	2.0		X(5167.6) *5188L*	5186.0	24.6 cored *83 log*	C	7*	C		7*	5	Ls/Dol
5712	Wilkerson 1-3	3	15	2	3-15N-2E	4953.4	4937.5	15.8	4917.0	4999.8	4984.0	46.4 cored	C	19*	C	1	11*	3, 0	Ls/ 2'dol
5818	Henry 1-3	3	15	2	3-15N-2E	X (4966)	4958.0	7.5	4938.0	X (4996.6) *5004.5L*	4997.5	30.6+ cored	C	3*	C		4*	3	Ls/5' dol/ls
5887	Williams 1-3	3	15	2	3-15N-2E	4943.5	4934.0	9.5	4914.0	4983.7	4974.0	40.2 cored	C	4*	C		5*	3	Ls/ 5' dol
5913	Boone 1-4	4	15	2	4-15N-2E	X (5037)	5028.0	6.5	5008.0	5066.5	5060.0	29.5+ cored *32 log*	C	6*	C		6*	3	Ls/ dol Ls/ 4' dol
5733	Toles 1-10	10	15	2	10-15N-2E	4964.0	X	na	na	5003.8 *5005.0L*	X	39.8 cored	C	8*	C		5*	3	Ls/ 2'dol
5899	McBride South 1-10	10	15	2	10-15N-2E	X (4962)	4947.0	13.3	4927.0	4996.2	4983.0	34.3 cored *36 log*	C	1*	C		5*	3	Ls/dol/ls
5705	Mary Marie 1-11	11	15	2	11-15N-2E	4961.0	4944.0	17.0	4924.0	5003.5	4988.5	42.5 cored	C	33*	C	4	14*	3, 0	Ls/ 2'dol
5934	Carter 1-14	14	15	2	14-15N-2E	X (4940)	4927.0	13.3	4917.0	4995.8	4983.0	56.1 cored *56 log*	C	16*	C		18*	3, 0	1'dol/ Ls/ 2'dol
6029	Kathryn 2-14	14	15	2	14-15N-2E	X(4994)	4990.0	3.5		5030.5	5027.0	36.5 core 38 *log*	C	4*	C		8*	3	Ls/Dol/Ls/Dol
5874	Joe Givens 1-15	15	15	2	15-15N-2E	5017.8	5010.0	9.0	4990.0	5044.0	5035.0	26.2 cored	C	0*	C		4*	3	Ls/ 0.1' dol
5943	Anna 1 - 15	15	15	2	15-15N-2E	4967.1	4947.0	20.1	4928.0	5004.7	4985.0	37.6 cored	C	10*	C		9*	3	Dol
6051	Carter Ranch 2-15	15	15	2	15-15N-2E	5006.0	5000.0	6.0		5035.1	5030.0	29.1 cored	C	5*	C		6*	3, 0	Ls/Dol
6247	Morrow 1-27	27	16	2	27-16N-2E	X(4905)	4886.0	0.5		4956.5	4956.0	53 cored *69 log*	C	8*	C		15*	4a, 3, 1?, 0	Ls/5' dol, keel oolite
5838	Danny 2-34	34	16	2	34-16N-2E	X (4930)	4918.0	10.8	4898.0	4984.3	4973.5	54.3+ cored	C	2*	C		11*	3, 0	Ls
6150	Mercer 1-28 *	28	17	2	28-17N-2E	X(4527)	4526.0	0 ?		X(4583) *4606L*	4606.0	56 cored *80 log*	C	5*	C		17*	5, 5a, 4b, 4a	16' Dol, 40' shaly Ls
6281	Chandler SWDW # 1-5	5	14	3	5-14N-3E	X(4810)	4797.5	12.0		X(4869.8) *4877.5L*	4865.5	59.8 cored *68 log*	C	6*	C		14*	5, 4b, 4a	31' dol/28' shaly Ls
5992	Carney Townsite 2-5	5	15	3	5–15N-3E	X (4906)	4907.0	0.0		X (4966); *4978L;*	4978.0	60 cored; *71 log*	C	8*	C		16*	5, 5a, 4a	Dol/Ls
6011	Bailey 2-6	6	15	3	6-15N-3E	X(4876)	4875.0	-2.8		X(4934)	4964.0	58 cored; *89 log*	C	20*	C		25*	5a, 4b, 4a, ?3	14' Dol/Ls
	Geneva 2-32 (not analyzed)	32	16	3	32-16N-3E	x(4889)	4873.0	15.0		x(4898.7) *4968ML*	4952.0 mudlogger	*9.7 ft cored 64' by mudlogger*	C	6*	NA		4*	5	Ls, Dol (Cri pkstn)
Totals												1510.9		219			305		

Wk = Work status (Core description), C = Completed; IP = In Process; PC = Porosity Codes.
TS = Thin Sections,# made, * described ; SEM = Scanning Electron Microscopy, Cono = Conodont micropaleontology, # of samples, * completed
UH = Core Plug samples at Univ. Houston; Wett = Wettability Analysis,
Hg Inj = Mercury injection porosimetry
Numbers in front of Well Name is StimLab well Identification Number

* Mercer not logged, but 75' offset (WFC Petroleum # 1-28 Cruse) was logged (N-D, Sonic, Lateral logs - same thickness as Mercer, 80') - Sandeep to digitize, Import digitized log data for Cruse 1-28 into Mercer 1-28
Note re core depth: Columns: "X ( )" indicate core depth of top & base of core, when formation top or base is not cored.
Numbers in italics followed by L, indicates equivalent core depth of base of Hunton converted form log depth. ML = mud logger depth.

A total of 1510.9 feet of core have been described. Porosity type and lithologic facies have been identified for each foot of analyzed core. An explanation of the numerical codes assigned to each porosity type and lithologic facies is given in Table 4. Part of the core analysis data is Grain Density for each analyzed sample. Table 5 provides a conversion from grain density to limestone-dolomite ratio for pure carbonate rocks.

Table 4: Explanation of Pore and Facies Codes: Porosity types and lithologic facies identified in this study.

A. <u>POROSITY TYPES</u>

LIMESTONES (grain density 2.71 to <2.73)

(Grain density numbers not shaded in Pore & Facies Code tables)

1. Interconnected Vuggy porosity

Vug or MO with IG, SF or other connection, Touching Vugs in general. Not separate vugs with tight matrix.

2. Coarse Matrix porosity

Inter-particle (IP) , IG or IX of coarse- and medium-grained and coarse crystalline rock, > .25 mm particle size. May include dissolution porosity that is inter-particle micro vugs (dissolution of spar or matrix).

3. Fine Matrix porosity

Inter-particle (IP), IG or IX of fine-grained and fine- to medium-crystalline rocks, < .25 mm particle size. Includes fine non touching vugs and non touching fine Moldic (MO) porosity along with intra-particle porosity

4. Fracture

FR or SF without significant matrix or vugs.

For this study, includes solution enhanced fractures with sand in-fill.

DOLOMITE (> 50% dolomite; grain density 2.79 or higher)

(Grain density numbers **bold** on Pore & Facies Code tables)

5. **Vuggy** (vug) or **Moldic** (MO) in coarse crystalline (IX) matrix (> .25 mm)
6. **Coarse crystalline** with Inter-crystalline porosity (IX) (> .25 mm)
7. **Medium to fine crystalline** (IX) (.25 mm to .02 mm)
8. **Fracture** FR or SF without significant matrix porosity

PARTLY DOLOMITIZED LIMESTONE (10 – 50 % dolomite; gr density 2.73-2.78)

(Grain density shaded gray on Pore & Facies Code tables)

9. Interconnected Vuggy porosity

Vug or MO with IG, SF or other connection, TV general, Vug general. Not vugs with tight matrix.

10. Coarse Matrix porosity

Inter-particle (IP) , IG or IX of medium- to coarse-grained and coarsely crystalline rock, > .25 mm particle size. May include dissolution porosity that is inter-particle micro vugs (dissolution of spar or matrix).

11. Fine Matrix porosity

Inter-particle (IP), IG or IX of fine-grained and fine- to medium-crystalline rocks, < .25 mm particle size. Includes fine non touching vugs and non touching fine Moldic (MO) porosity along with intra-particle porosity

12. Fracture

FR or SF without significant matrix or interconnected vuggy porosity.

For this study, includes solution enhanced fractures with sand in-fill.

B. FACIES TYPES

Code #

1. Argillaceous Dolomite: Greenish-gray, Sylvan Fm and similar facies.

2. Crystalline Dolomite: Original fabric obscured, or simply fine crystalline replacement

3. Small Brachiopod Grainstone/Packstone/Wackestone

4. Fine Crinoid Grainstone/Packstone/Wackestone: Medium-grained and smaller.

5. Coarse Crinoid Grainstone/Packstone: Coarse-grained and larger

6. Mixed Crinoid-Brachiopod Grainstone/Packstone/Wackestone

7. *Pentamerus* Brachiopod Coquina: Robust, thick-shelled pentamerid brachiopods dominate rock.

8. Corals, Stromatoporoids, & Brachiopods: Diverse fauna grainstones to wackestones, crinoid debris & byrozoa common.

9. Coral & Crinoid Grainstone-Wackestone: Similar to 8, lacks significant brachiopods

10. Sparse Fossil Wackestone: sparsely fossiliferous

11. Calcimudstone: Lime mudstone, very sparsely fossiliferous.

12. Fine- to Medium Grainstone: a description used only when the faunal components cannot be identified.

13. Shale: siliciclastic

14. Fine Sandstone: siliciclastic.

15. Stricklandid Brachiopod Facies: Brachiopod grainstones dominated by big thin-shelled pentamerids, probably *Stricklandia*.

16. Oolitic carbonate: Includes oolitic dolomite, and oolitic chert replacing carbonate.

17. Karst Breccia & Cave Fill Parabreccia

18. Nodular Calcimudstone or Wackestone: Shaly partings create nodular fabric.

19. Shale with Calcimudstone Nodules: Dominantly shale, but calcimudstone nodules common.

20. Fine Fossil Wackestone: Very fine-grained wackestone & packstone with diverse microfauna; typically < 125 micron size. Commonly contains crinoid debris, ostracodes, brachiopod spines & fragments, bryozoa, small trilobites, sponge spicules, & coral fragments.

Table 5: Conversion from Grain Density to Limestone-Dolomite Ratio

GRAIN DENSITY	% LIMESTONE	% DOLOMITE
2.71	100	0.
2.72	93	7
2.725	90	10
2.73	87	13
2.74	80	20
2.75	73	27
2.76	67	33
2.77	60	40
2.78	53	47
2.785	50	50
2.79	47	53
2.80	40	60
2.81	33	67
2.82	27	73
2.83	20	80
2.84	13	87
2.845	10	90
2.85	7	93
2.86	0	100

References

Barrick, J.E., in press, The Silurian stratigraphic succession in the southern Midcontinent region of North America: New York State Museum Bulletin. (Expected publication, 2005)

Amsden, T.E., and Barrick, J.E., 1993, Pre-Woodford Subcrop map and stratigraphic sections of the Anandarko Basin: Oklahoma Geological Survey Map GM-34, 2 plates and appendix, 20 p.

Engineering Analysis

Log and Production Data Evaluation

Manas Gupta, Rahul Joshi and Mohan Kelkar, The University of Tulsa

Introduction

This report continues the development of the methodology described in the previous report. To improve a better understanding of the petrophysical and production characteristics of Hunton, additional areas have been included in this report. These areas have been included to see whether they show the same properties as shown by the West Carney Field and also to recommend the possibilities of developing these areas further. Log and production data, were collected for wells drilled in these areas.

The areas which have been included are:

1. Chandler (14N3E)
2. Seminole (11N6E and 11N7E)
3. Alabama (9N11E)

The map (Figure 8) below shows the location of the West Carney Area with respect to Chandler, Alabama and Seminole area.

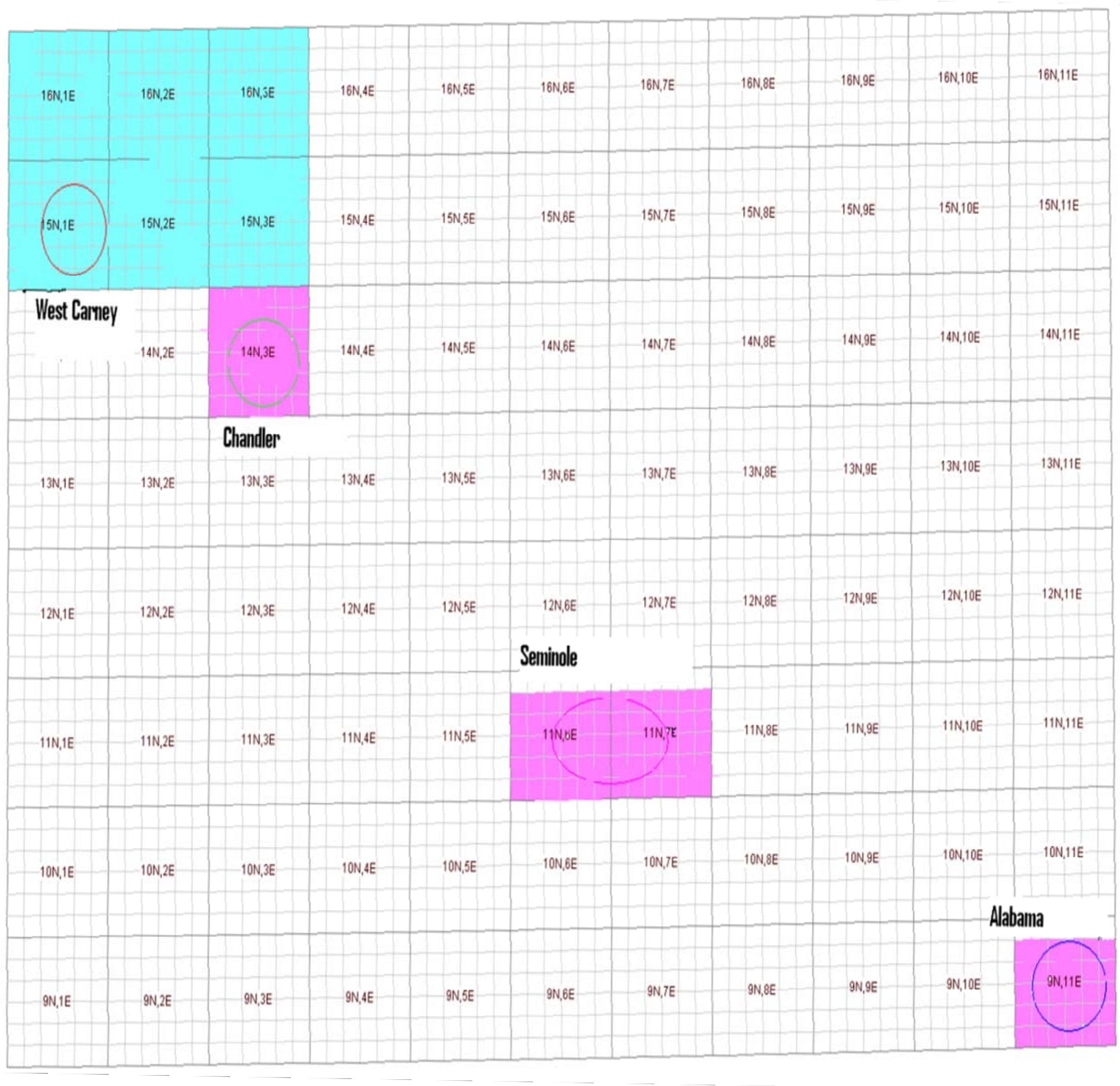

Figure 8: Areal Map of the Areas Studied

Approach

West Carney Field was divided into four regions: Central East, Central West, East and West. The map of the four areas is shown in Figure 9. Porosity and resistivity logs were also collected for Chandler, Alabama and Seminole areas. Hydrocarbon saturation at each well location was then calculated using resistivity and porosity logs by Archie's equation.

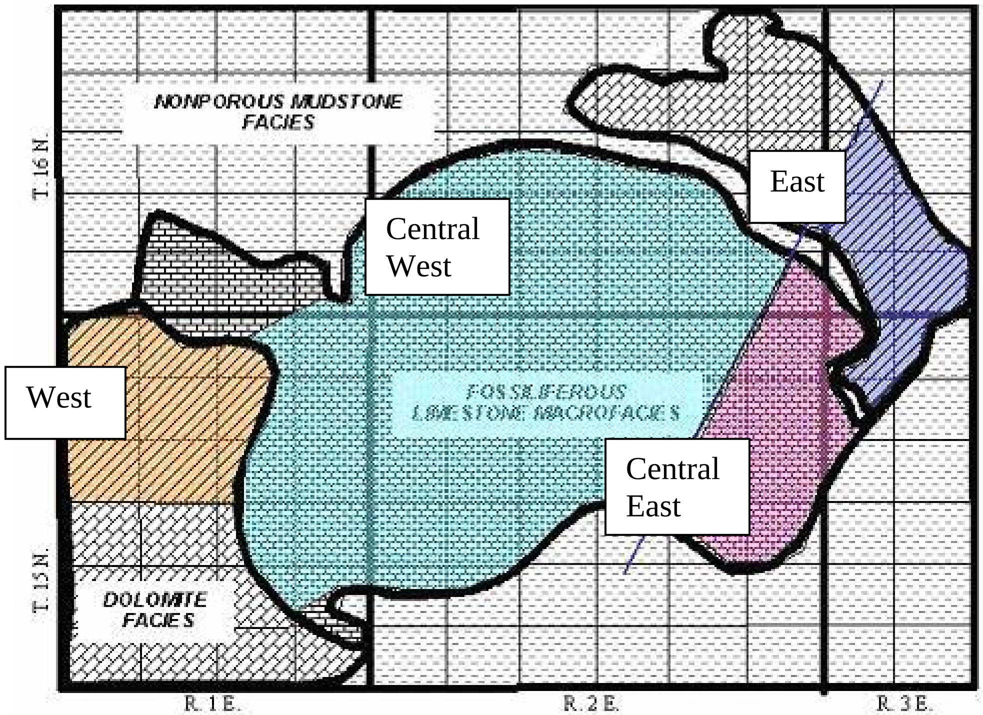

Figure 9: Geology map showing the four regions of West Carney field

Statistical properties were then calculated using the porosity and saturation values at individual well locations. The property values calculated for each of the regions are shown in Table 6. The well density is calculated by dividing total number of wells by the number of 160 acre sections within each region. That is, if the well density is 1, it indicates that one well is drilled per 160 acres.

Table 6: Summary of Saturation and Porosity Data from Different Regions

Region	Oil Saturation	Water Saturation	Porosity	Std Porosity	Std Saturation	Well Density
Central West	0.48	0.52	0.0454	0.024	0.203	0.71
Central East	0.486	0.513	0.0452	0.027	0.220	0.77
East	0.382	0.617	0.067	0.034	0.170	0.8
West	0.279	0.72	0.079	0.045	0.195	0.57
Seminole	0.578	0.421	0.045	0.013	0.091	0.277
Chandler	0.384	0.616	0.130	0.052	0.174	0.215
Alabama	0.484	0.515	0.048	0.018	0.075	0.17

Table 6 shows that average porosity of Seminole and Alabama area are the same as that of Central East and Central West Region; though Seminole shows higher oil Saturation than Central West and Central East. Also Seminole shows a very low value of standard deviation of porosity. As we had seen in previous reports that low standard deviation of porosity means higher saturation; thus saturation is consistent with prior observations. Seminole, Chandler and Alabama regions also have low well density which means that these areas have not been fully developed.

To investigate the data further petrophysical models were then developed in Petrel Software for Alabama, Chandler, Seminole, and for each of the four regions in the West Carney Field. These models were generated using the well locations and depth of Hunton at each well location. Resistivity and porosity logs were then imported for each of the wells into Petrel. Hydrocarbon saturation was calculated using these values of porosity and resistivity. Saturation values at inter-well locations were determined using krigging technique to generate a saturation map for the region. Petrel then calculates the Oil in Place (OIP) at reservoir conditions using this saturation map and the geological model constructed for each of the regions. Oil in Place for each of the regions is shown in Table 7.

The gas in Place (GIP) is calculated by multiplying OIP by initial solution gas oil ratio (Rsi). Using the observed reservoir fluid properties and assumed bubble point, we have estimated the initial gas in oil ratio to be 650 SCF/STB. Thus the Oil in Place and Gas in Place under standard conditions are as follows:

Table7: Oil in Place for Different Regions

Region	Oil in Place (Reservoir Condition) MMRB	Oil in Place (MSTB)	Gas in Place (bcf)
Central West	226.69	174,380	113
Central East	33.06	25,400	17
East	77.07	53,900	35
West	91.82	70,630	46
Seminole	731.48	562,600	366
Chandler	530.27	407,900	265
Alabama	59.29	45,600	30

The above table shows that Chandler and Seminole Areas show high values of Hydrocarbon in place. It must be stated that OIP calculations and Chandler area have lot of uncertainties because of limited well control. In contrast, in other areas, we have a better well control.

Plot of Oil in Place (OIP) for the Central West, Central East, East, West, Alabama, Seminole and Chandler Areas are shown in the following figures

A. Central West

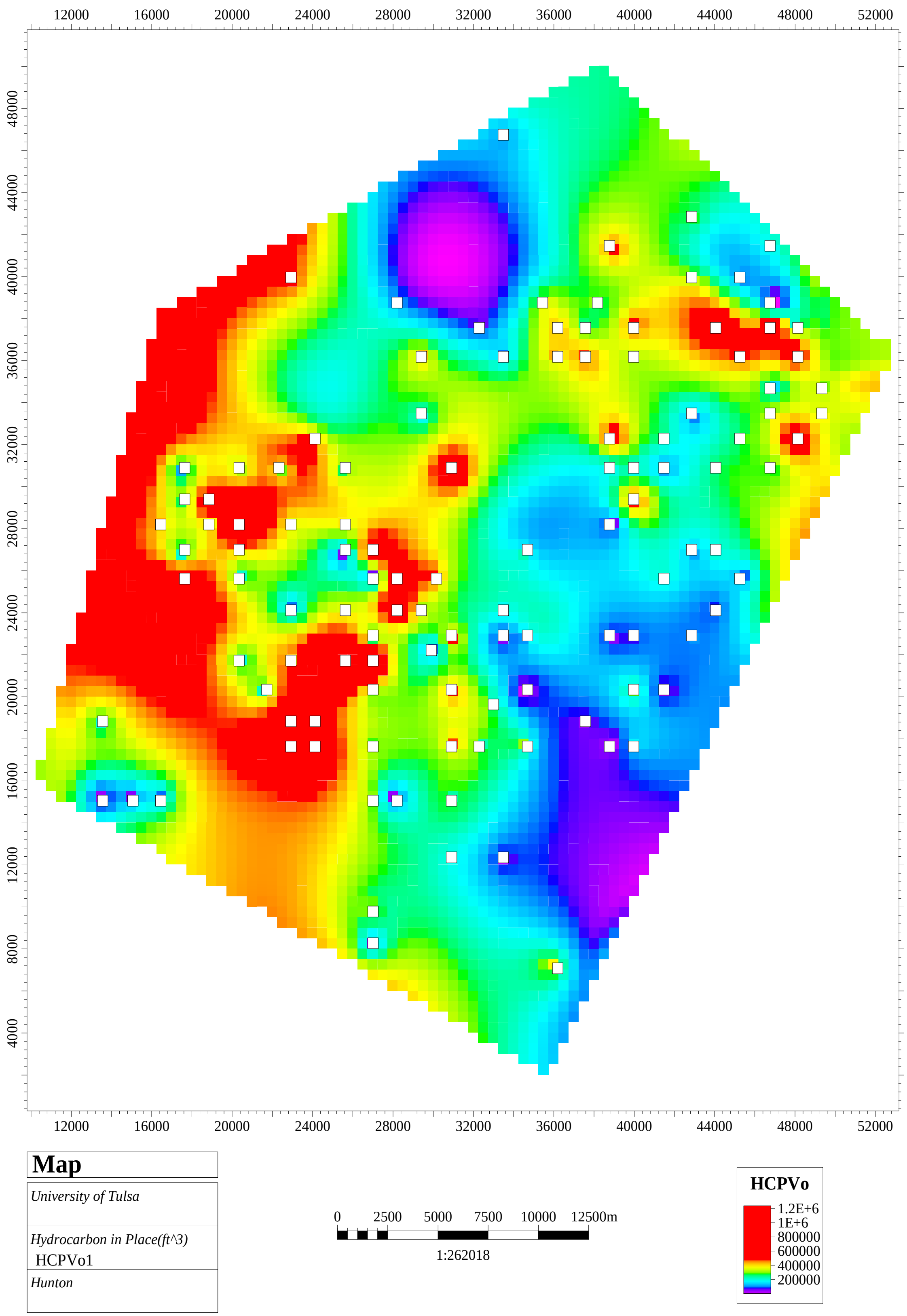

Figure 10: Oil in Place (OIP) for Central West region

B. Central East

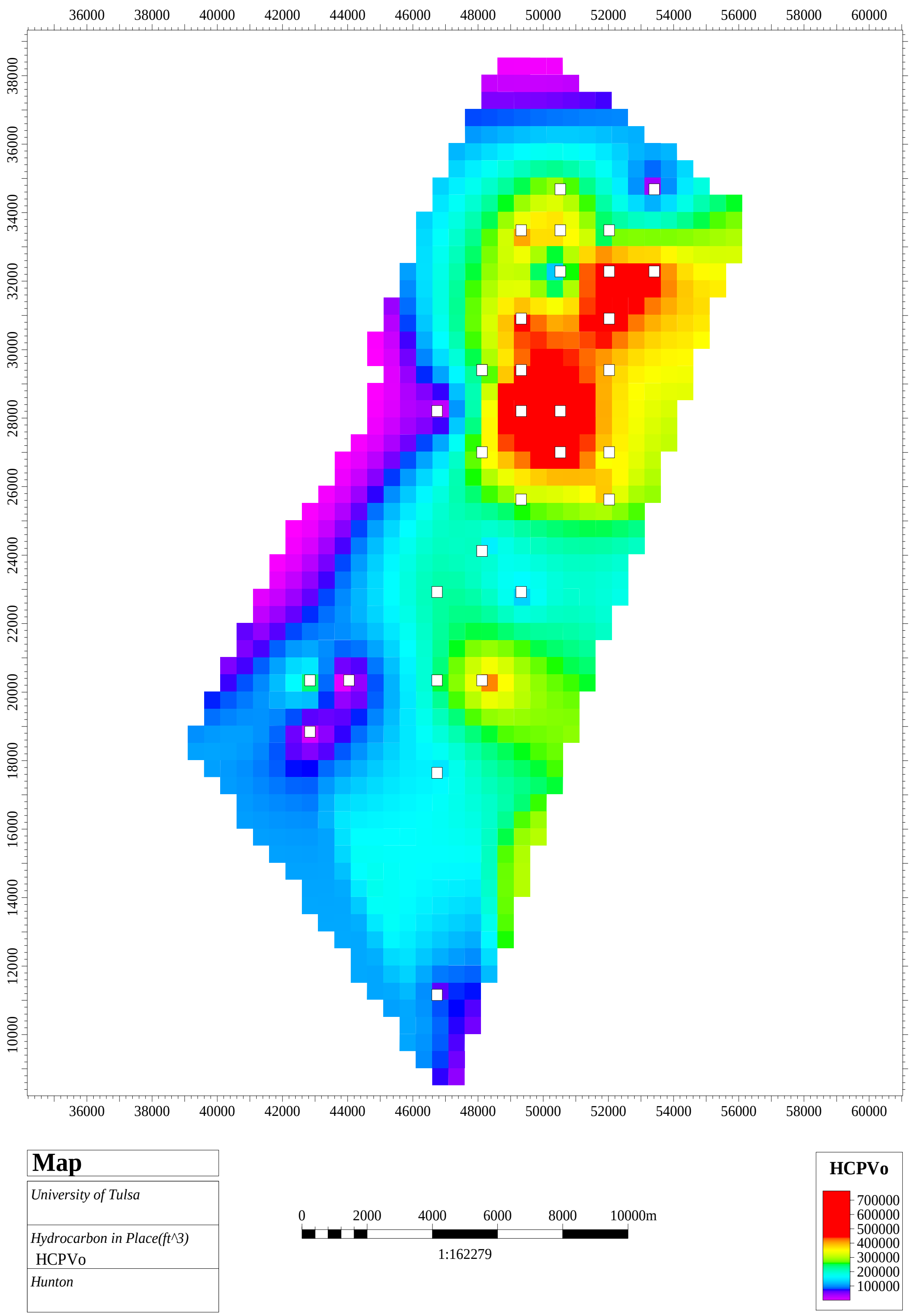

Figure 11: Oil in Place (OIP) for Central East region

C. East

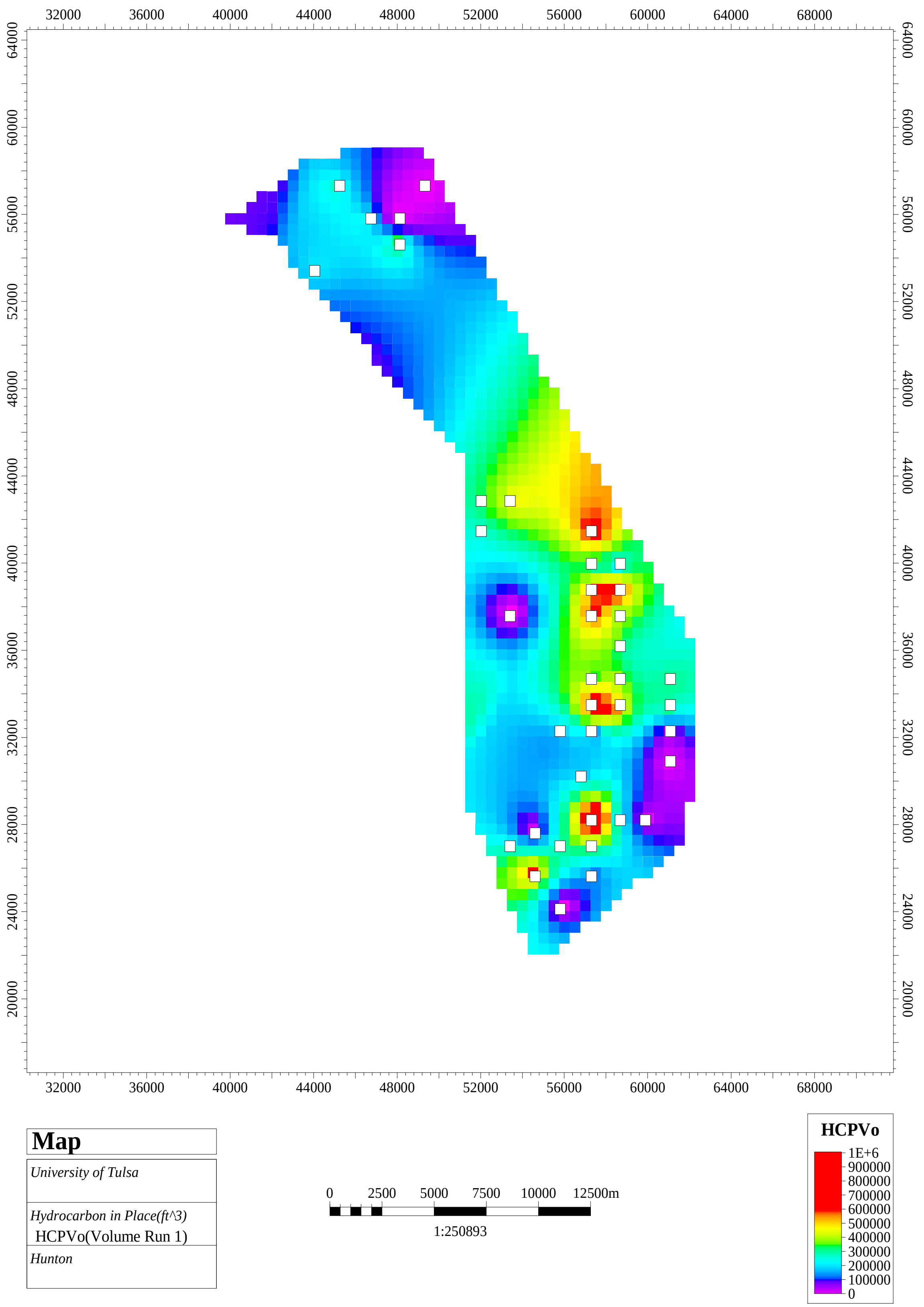

Figure 12: Oil in Place (OIP) for East region

D. West

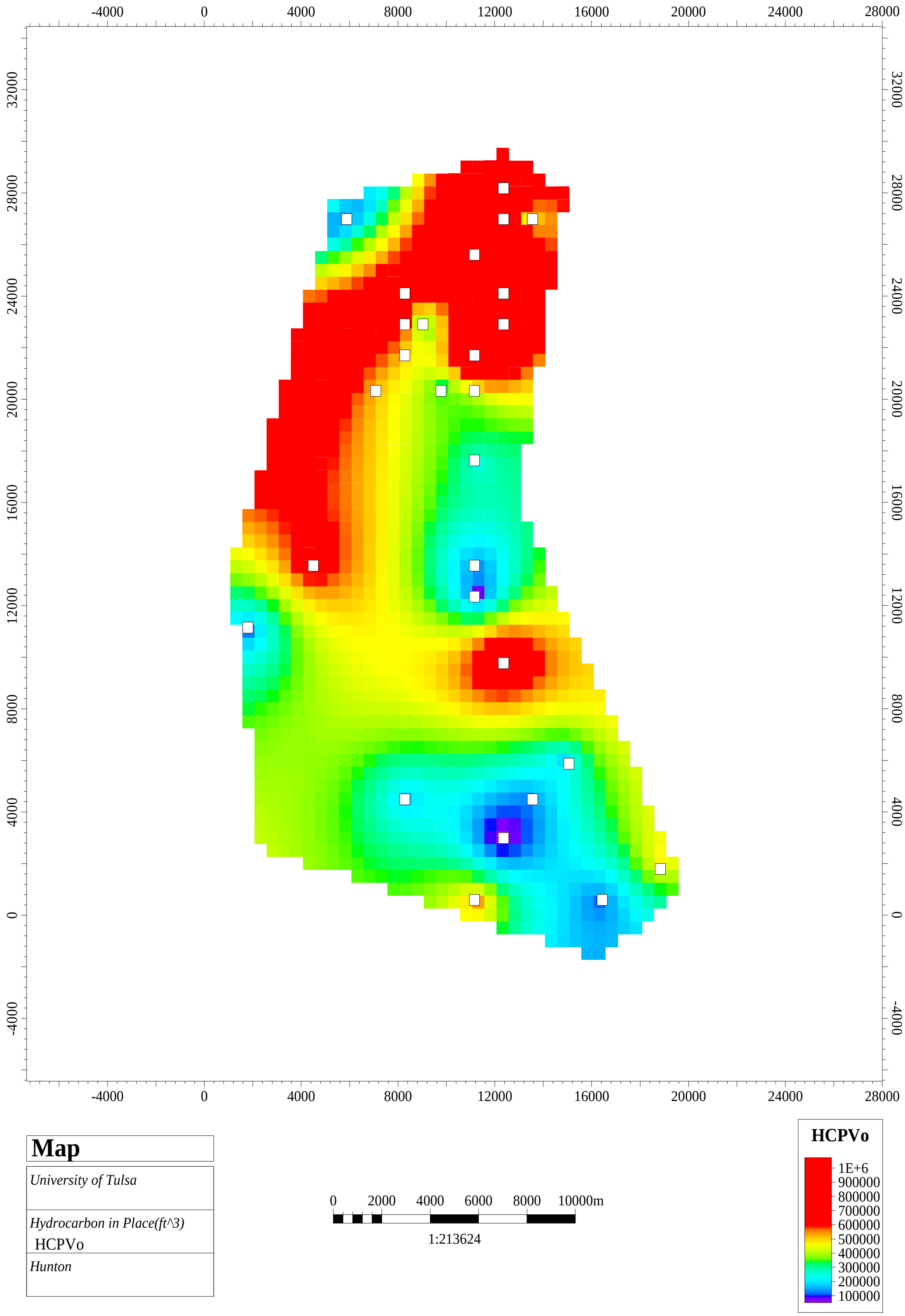

Figure 13: Oil in Place (OIP) for West region

E. Alabama

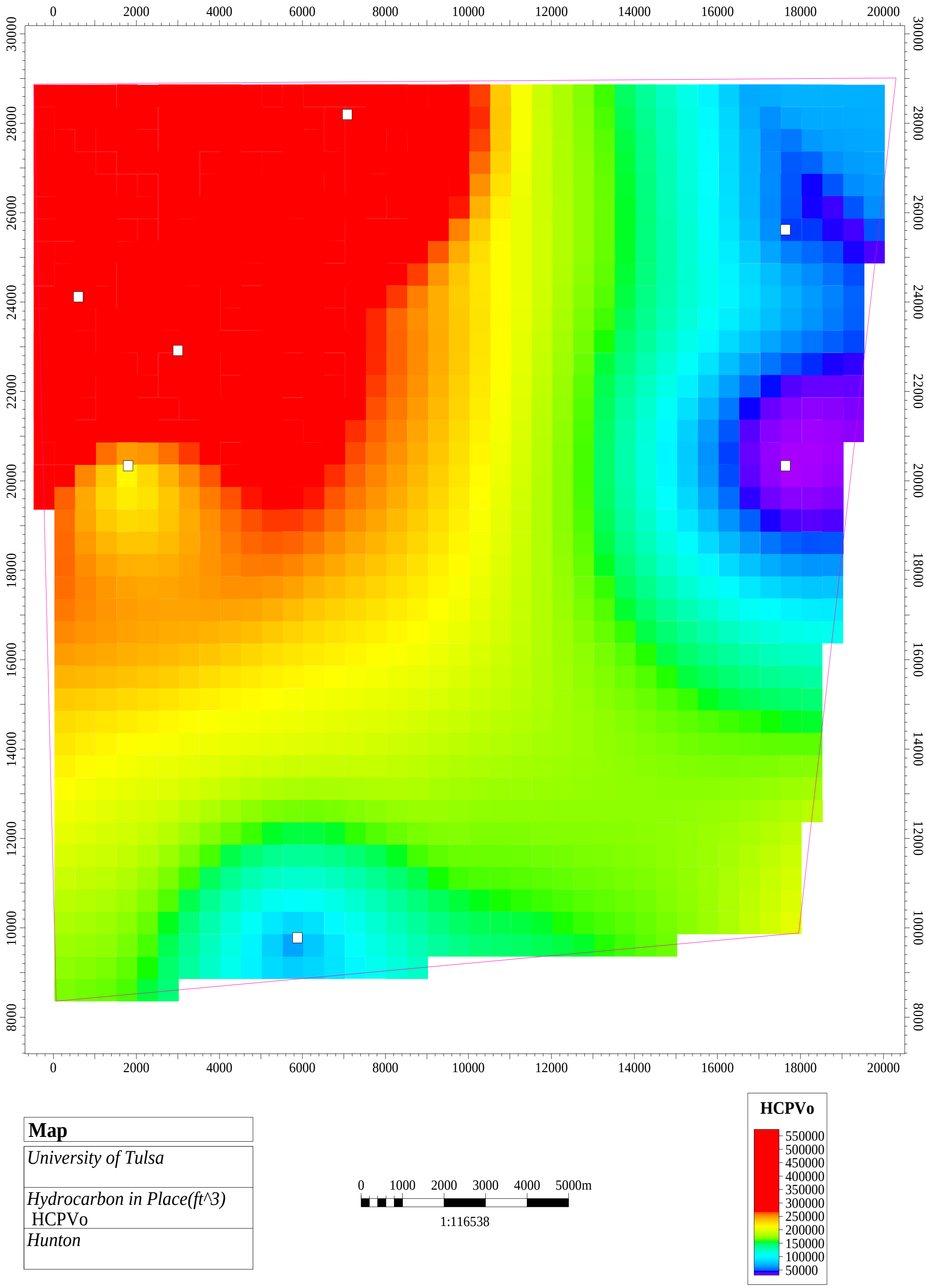

Figure 14: Oil in Place (OIP) for Alabama

F. Chandler

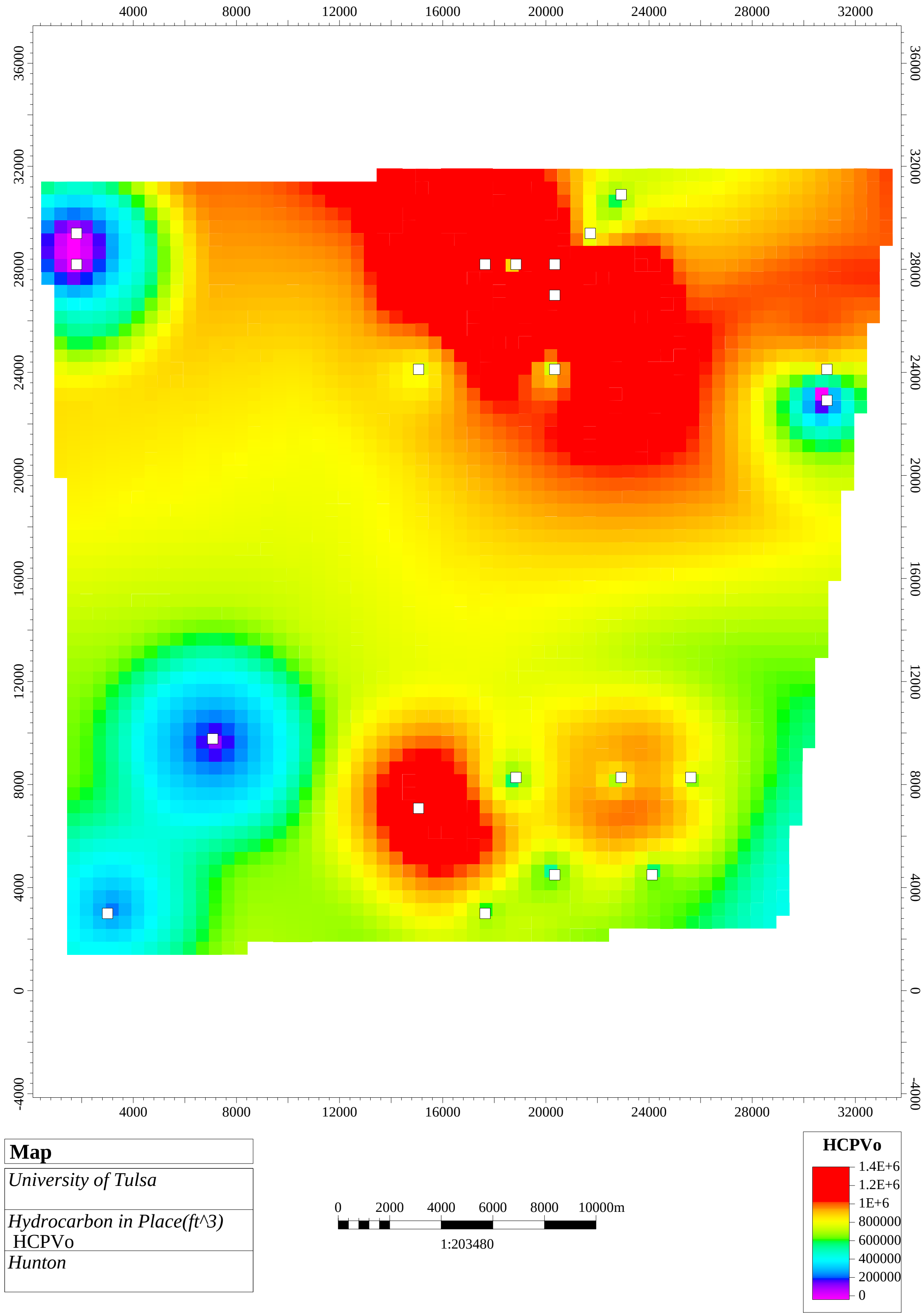

Figure 15: Oil in Place (OIP) for Chandler

G. Seminole

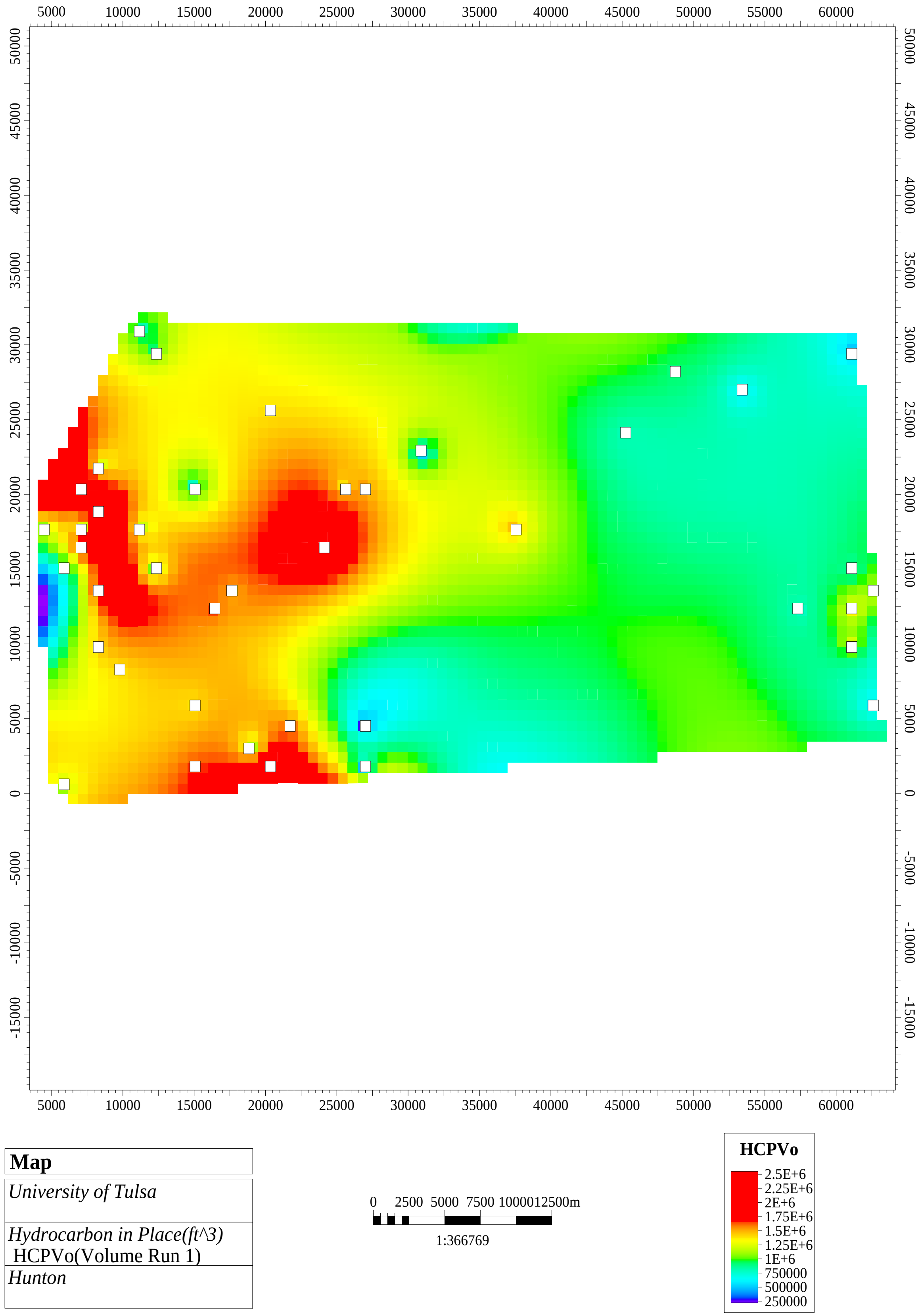

Figure 16: Oil in Place (OIP) for Seminole

Recovery Calculation

Oil and Gas production data for each well were collected and decline curve analysis was conducted to determine the ultimate recoverable reserves from each well. The abandonment rate of Oil and gas was taken as 0 BBL/D and 0 MSCF/D respectively. Thus the total recoverable reserve for a region is the sum of recoverable reserves from each well.

The total recoverable reserves for each of these regions are as follows:

Table 8: Recoverable Reserves based on Individual Wells

Region	Oil Reserves(MBBL)	Gas Reserves(bcf)
Central West	4,635.11	40.27
Central East	2,234.60	6.96
East	2,226.50	24.94
West	416.60	11.50
Seminole	237.70	5.59
Chandler	1,378.80	1.07
Alabama	977.70	0.81

To confirm whether these values are accurate, decline curve analysis was also done on regional basis for the West Carney Field. Total hydrocarbon produced from a region was calculated for each month and then regional decline curve analysis was done. The total recoverable reserves thus calculated are shown in Table 9.

Table 9: Recoverable Reserves in West Carney based on Regional Decline

Region	Oil Reserves(MBBL)	Gas Reserves(bcf)
Central West	4,430.00	42.55
Central East	2,177.20	6.95
East	2,417.50	19.50
West	394.80	12.49

It can be seen that the reserves calculated by the two methods are in close proximity, which validates that the values calculated on the basis of individual well decline curve analysis are fairly accurate.

Recovery factor was then calculated for each of the regions by dividing the total ultimate recoverable reserves by in place Hydrocarbons

The Recovery Factors are shown in Table 10.

Table 10: Gas and Oil Recovery Factors for Different Regions

Region	Recovery Factor (Oil)	Recovery Factor (Gas)
Central West	0.0260	0.3500
Central East	0.0880	0.4213
East	0.0410	0.7100
West	0.0060	0.2436
Seminole	0.0004	0.0150
Chandler	0.0033	0.0040
Alabama	0.0214	0.0270

From Table 10 it can be seen that Central East shows a greater oil recovery than Central West. The recovery factors of hydrocarbons for Seminole and Chandler area is the least which can be due to low well density. It is also worth pointing out that gas recovery factor is greater than oil recovery factor. This is consistent with the idea that gas tends to be more mobile than oil phase.

Recovery Factor per Section Area

To investigate the effect of well density or the number of wells on the recovery of hydrocarbons or on the recovery factor, geological model for the West Carney area was constructed in Petrel for a grid size of 640 acres. The total recovery of oil and gas for a particular 640 acre grid block was calculated as the sum of the recovery of all the wells in that grid block. This was done for all the grid blocks in a region and also the number of wells in each grid block was determined. Plots were then generated between recovery and the number of wells for each region in the West Carney field to determine the relation between well density and recovery. In these plots we show the total recovery as a function of the number of wells as well as the recovery per well as a function of the number of wells. Please note that the data points in these plots represent the average of many 640 acre sections in each region. For example, in West Carney area, if there are twenty, 640 acre, sections where the number of wells drilled is equal to 4, then the total recovery from all the twenty sections is averaged and plotted on the graph. The same is done for the recovery per well. Thus the plots shown below represent the average behavior across the region.

The Plots for the West Carney regions are as follows:

A. Central West

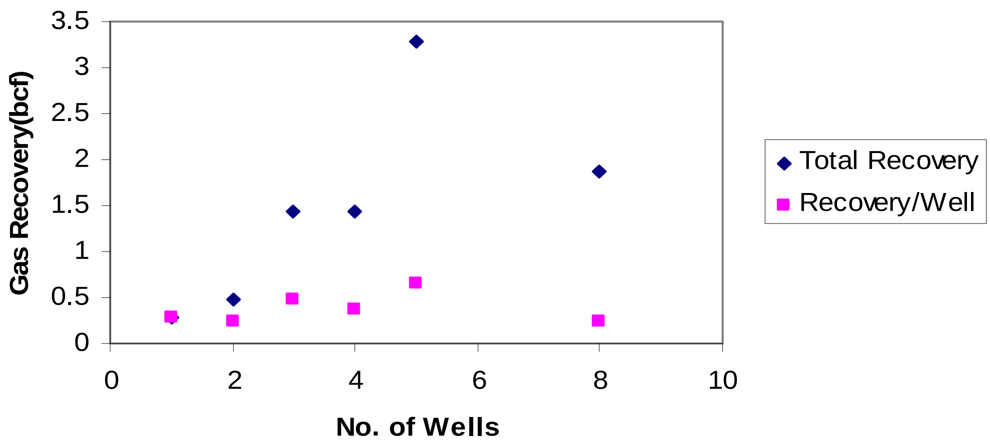

Figure 17: Gas recovery vs. No. of wells for Central West region

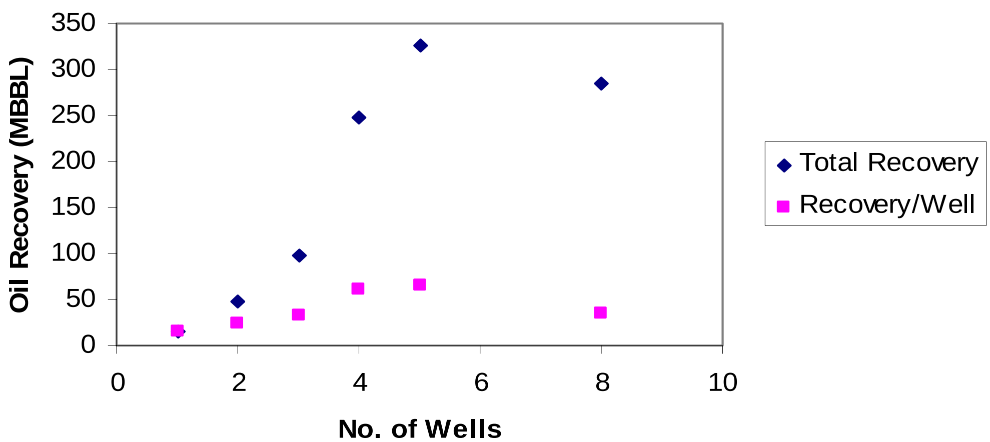

Figure 18: Oil recovery vs. No. of wells for Central West region

From the above figures it can be seen that the oil and gas Recovery increases with the increase in the number of wells in a particular section, but the recovery per well first increases and then decreases. This shows that there is an optimal number of wells for which the recovery per well is maximum. The plots show that the optimal number of wells is 4-5 wells per section. Also it can be seen that gas recovery per well remains relatively flat as compared to oil recovery per well which can be explained due to the high mobility of gas as compared to oil mobility.

B. Central East

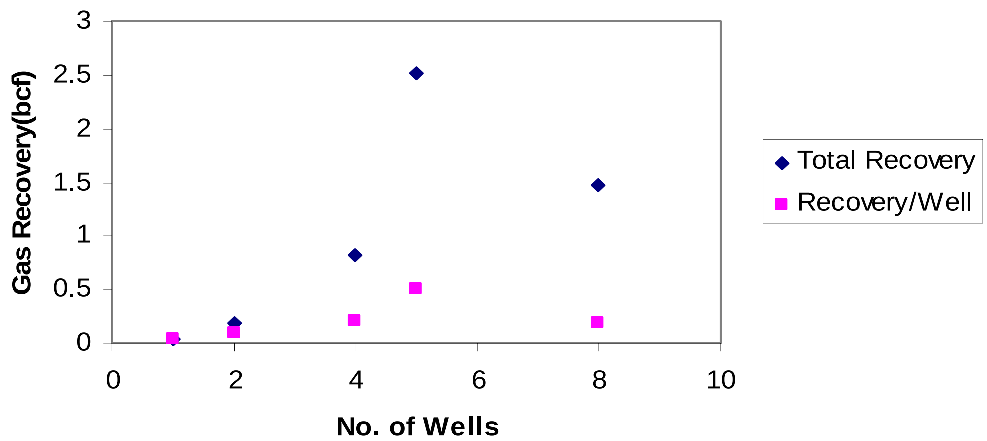

Figure 19: Gas recovery vs. No. of wells for Central East region

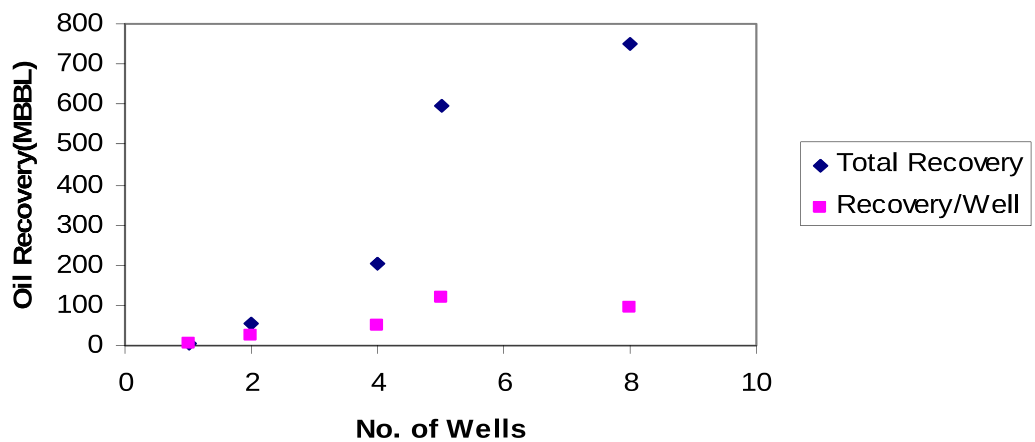

Figure 20: Oil recovery vs. No. of wells for Central East region

In the Central East region it can also be seen that the recovery in a section increases with the number of wells but the recovery per well goes through an optimal value. The plots show that the optimum number of wells is 4-5 wells per section.

C. East

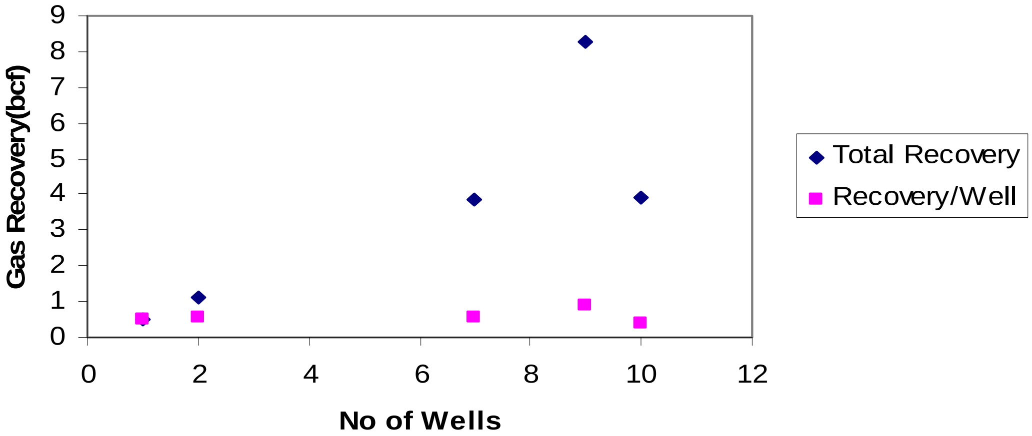

Figure 21: Gas recovery vs. No. of wells for East region

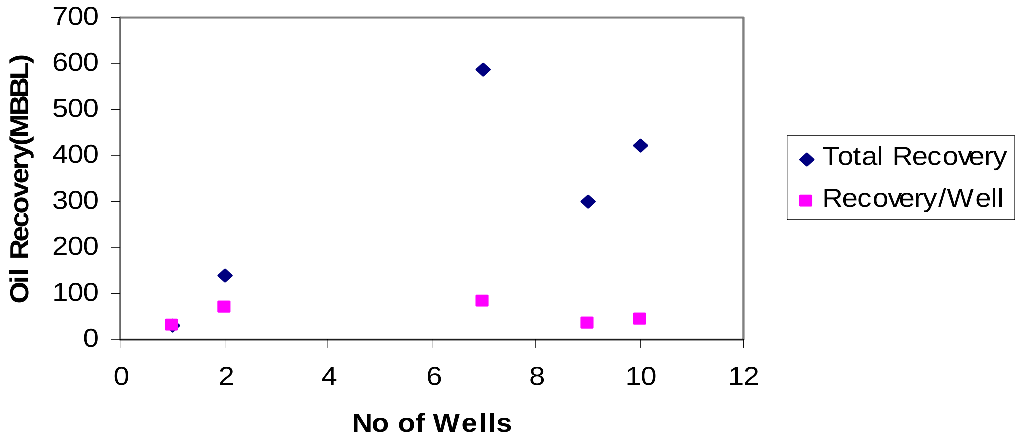

Figure 22: Oil recovery vs. No. of wells for East region

In the East region also the Recovery/Well decreases for sections with wells more than the optimal number of wells. The optimal number of wells is equal to 4-5 wells per section.

D. West

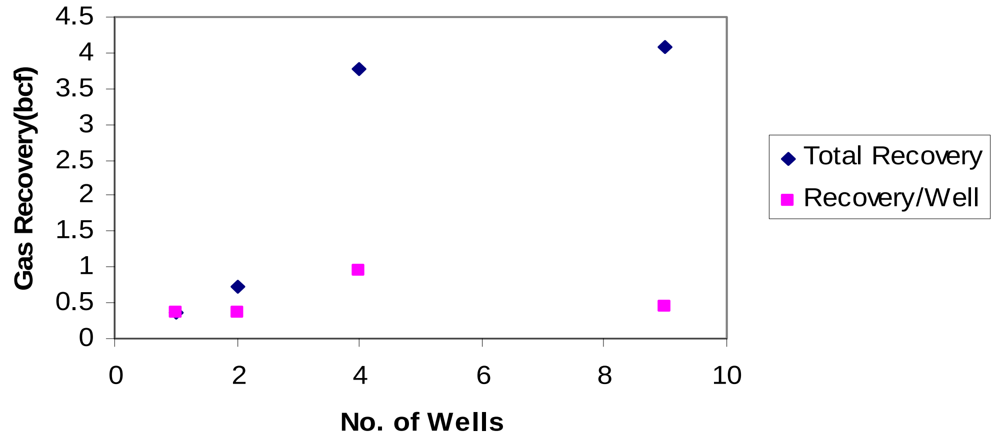

Figure 23: Gas recovery vs. No. of wells for West region

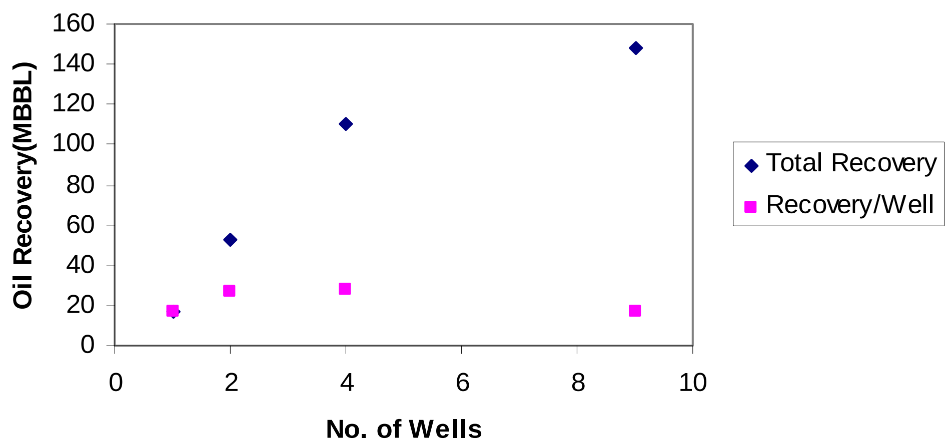

Figure 24: Oil recovery vs. No. of wells for West region

West region also shows that gas recovery and oil recovery increases with the number of wells but recovery/well goes through an optimal value.

Thus above plots show that there are an optimal number of wells which can be drilled in a section to maximize recovery per well. Economically it would not be feasible to have wells more than the optimum value as the recovery per well will decrease and capital spent on drilling an extra well will not be justified. Also the gas recovery per well for a section tends to be relatively flat as compared to oil recovery per well which can be explained by understanding that oil tends to be less mobile compared to gas. Thus, we need more drilled wells to increase the oil production.

Thus in areas like Seminole which show high value of mobile oil saturation, high value of oil in place and low well density; more wells need to be drilled to optimize recovery. The number of wells drilled per section needs to be increased to 4- 5 wells in order to enhance recovery. Thus area like Seminole show good promise and are good prospect for further development.

Analysis of Pressure and Water Production Data

Bottom hole pressure data was collected for wells in the West Carney region. BHP was then plotted as a function of time to see the pressure behavior for these regions.

A. Central West

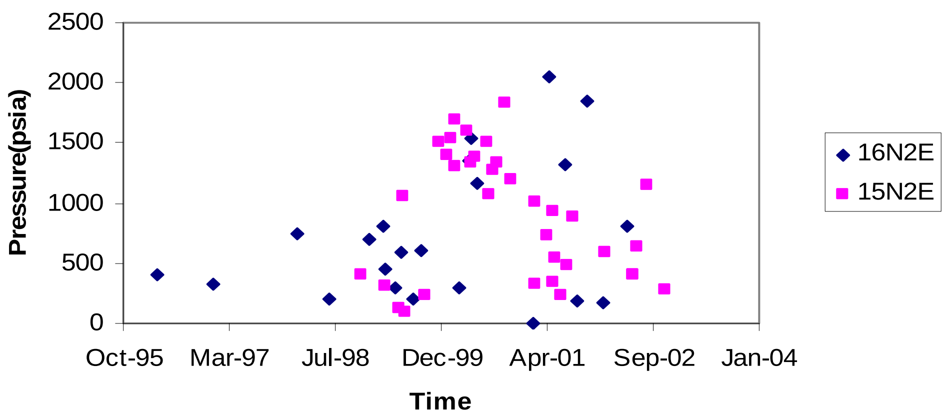

Figure 25: BHP vs. Time for Central West region

For the Central West Region it can be seen that the pressure for Township 15N2E has decreased considerably. This is due to the high well density in this region and good connectivity in the reservoir. Also for 16N2E there is a general decline in pressure though some wells are showing high BHP.

The decrease in reservoir pressure can further be corroborated by plotting water production with time. Unfortunately we had water production data from wells drilled by Marjo only.

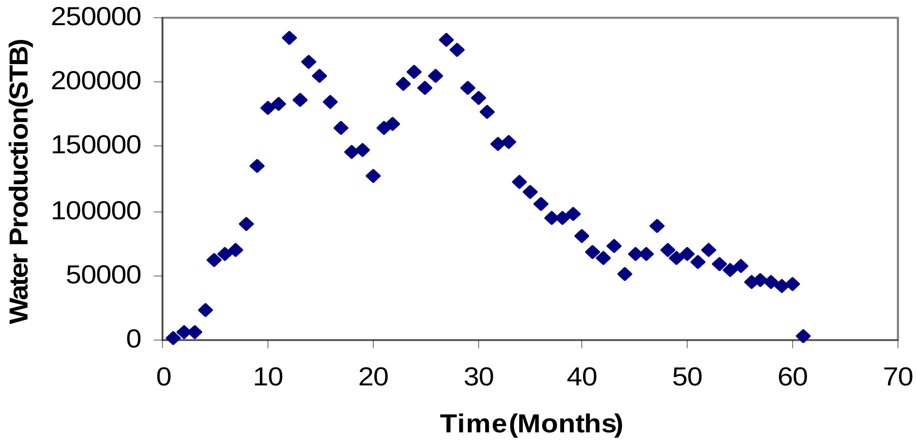

Figure 26: Water production vs. Time for Central West region

Figure 26 shows that the water production has decreased considerably with time which further proves that the reservoir pressure has reduced considerably for Central West region.

Though the reservoir pressure has decreased with time but still the recoverable reserves have not decreased considerably. This can be seen in Figure 27 and Figure 28 which area plots of recoverable reserves of Gas and Oil for each well and the time at which these Wells were put to production. If the recovery is a function of pressure, then gas and oil reserves should decrease with time. However, the plots indicate that recovery of gas is randomly distributed. The oil recovery does indicate some weak trend, indicating that the recovery is declining with time.

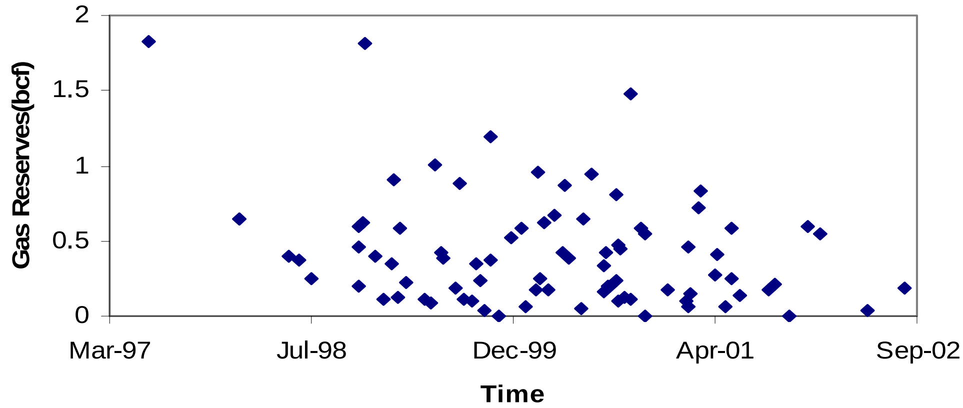

Figure 27: Gas reserves vs. Time for Central West region

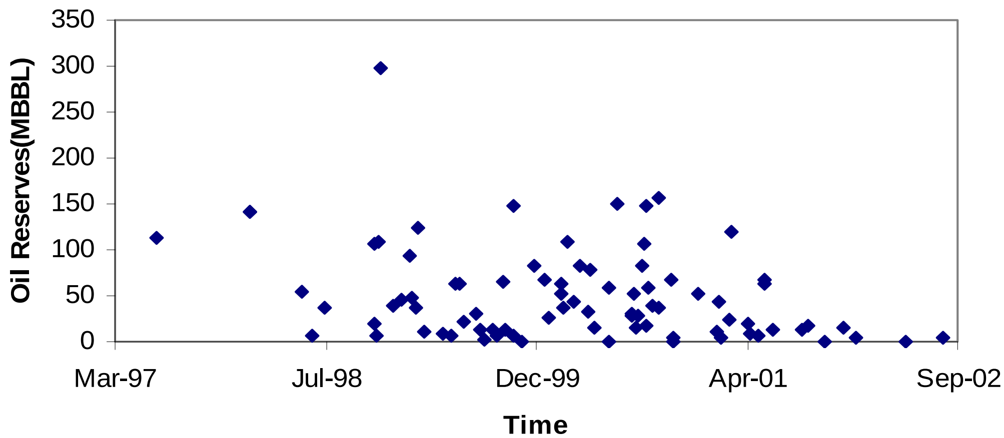

Figure 28: Oil reserves vs. Time for Central West region

From the above plots it can be seen that the recoverable reserves have not decreased considerably for wells drilled later. Though some of the wells put into production after April 2001 show less oil recovery but still they show good gas recovery. This is probably due to better mobility of gas compared to oil.

B. Central East

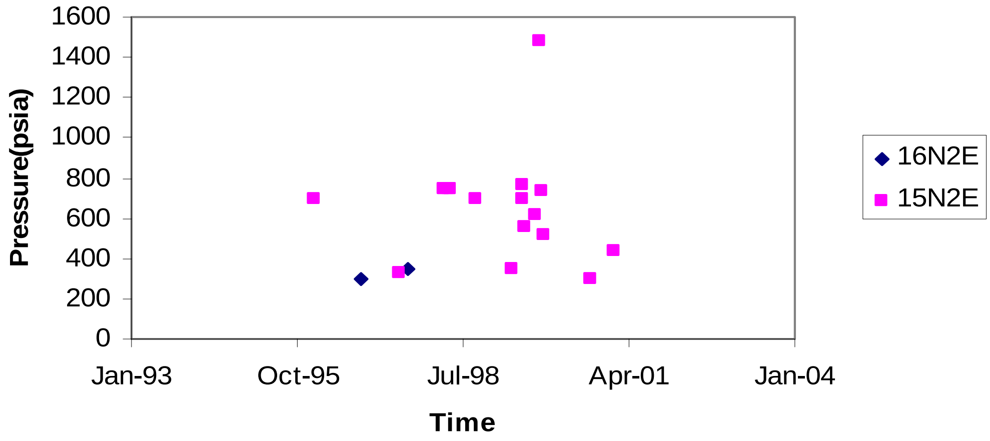

Figure29: BHP vs. Time for Central East region

In Central East region as well, the pressure for 15N2E has decreased considerably (Figure29) since the time it was brought into production. This is mainly due to very good connectivity between wells. Also from Figure 30 below it can be seen that the water production has decreased considerably which further proves that the reservoir pressure has decreased.

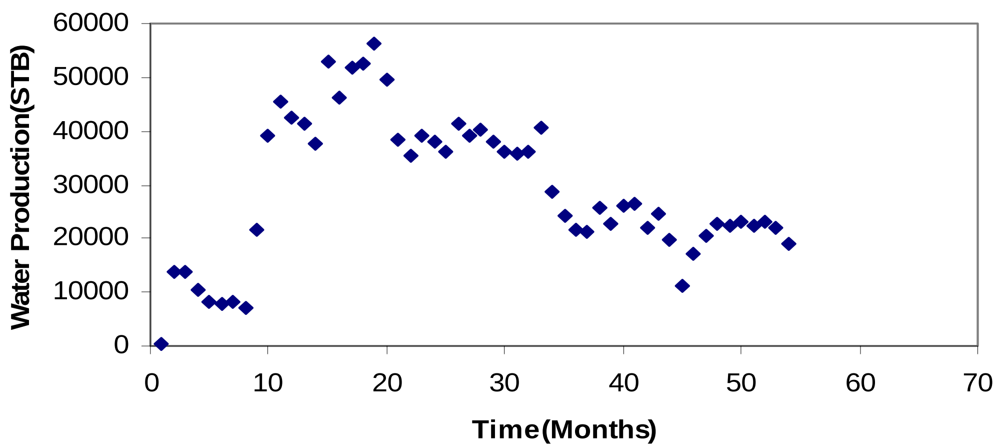

Figure 30: Water production vs. Time for Central East region

Though the Reservoir Pressure has decreased but still the recoverable oil and gas reserves do not show a decreasing trend with time. This can be seen from the plots below.

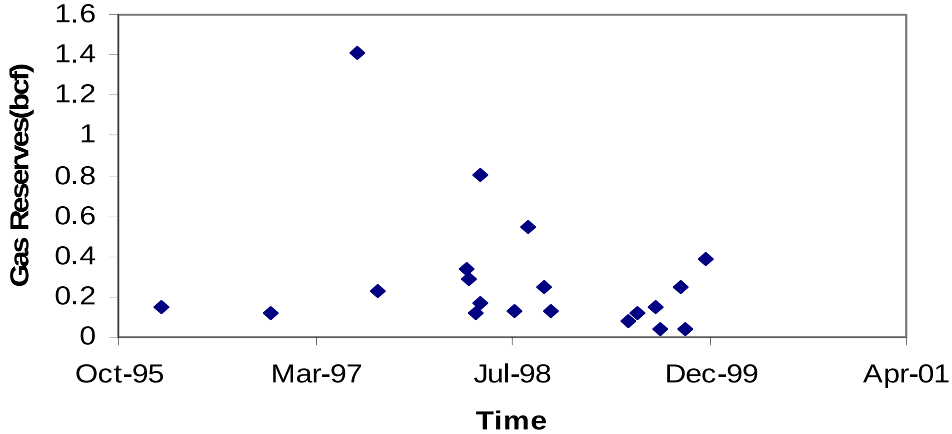

Figure 31: Gas reserves vs. Time for Central East region

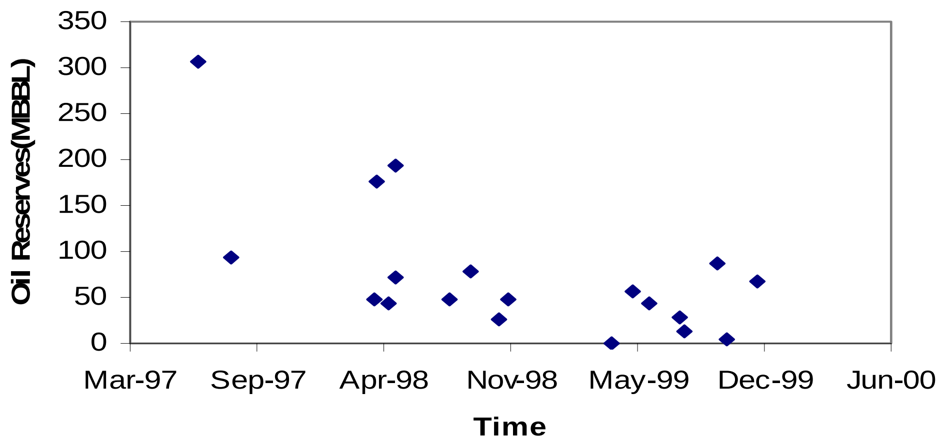

Figure 32: Oil reserves vs. Time for Central East region

Figures 31 and 32 show that the oil and gas Reserves do not depend only on pressure but on other factors like IP, Saturation, section (location) where the well is being drilled and also on the well density at that particular section

C. East

Figure 33 is the plot of Bottom Hole Pressure with time for wells in the East Region.

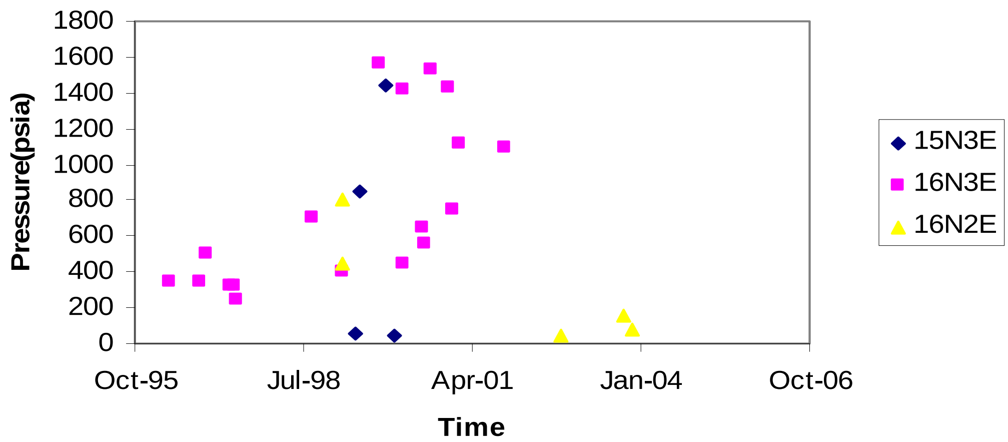

Figure 33: BHP vs. Time for East region

In East region we cannot see a declining trend in the reservoir pressure with time. This is possibly because we have data for very few wells drilled after April 2001. But some wells drilled in 2003 show a very low reservoir pressure. This means that the reservoir pressure has decreased considerably which can be further affirmed by Figure 34 which is a plot of Water Production (Marjo wells) with time.

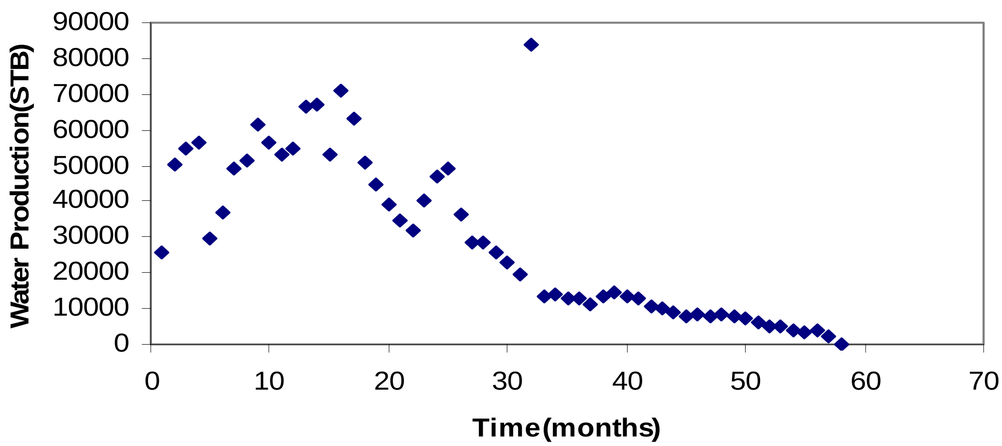

Figure 34: Water production vs. Time for East region

Though the reservoir pressure has decreased with time but still the recoverable reserves do not depend on the pressure only as can be seen from Figures 35 and Figures 36.

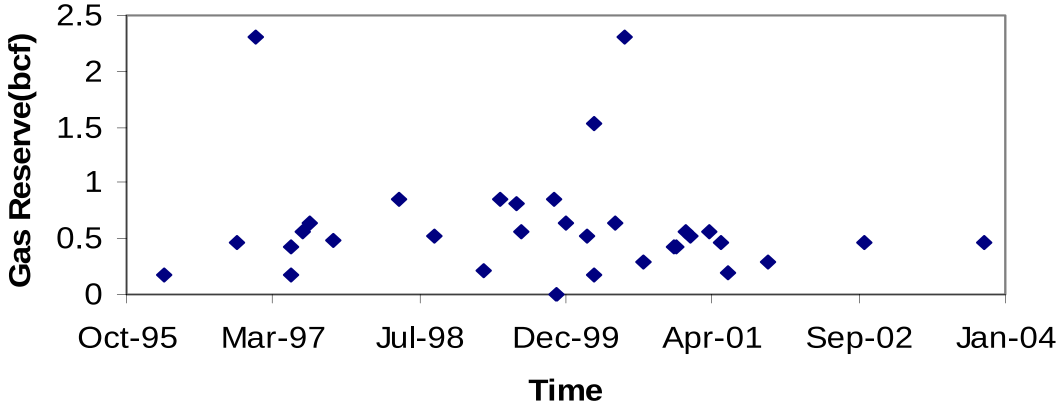

Figure 35: Gas reserves vs. Time for East region

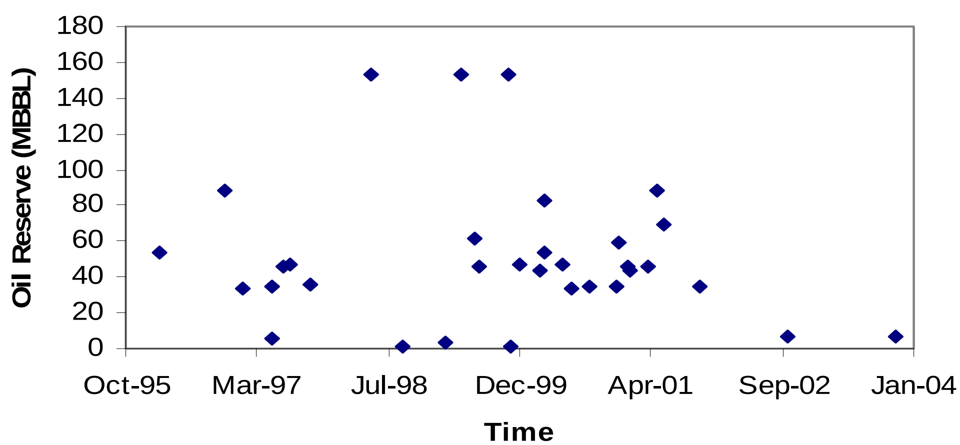

Figure 36: Oil reserves vs. Time for East region

Figures 35 and 36 show that the recoverable reserves do not depend only on the reservoir pressure, but also on many other factors like IP, location, saturation, and well density.

D. West

Figure 37 which is a plot of Bottom Hole Pressure with time shows that the Pressure of West Carney has reduced considerably. In West region there has been a very steep decline in pressure which can be attributed to the high volumes of water that has been produced from this region. West Carney shows a very good connectivity between the wells.

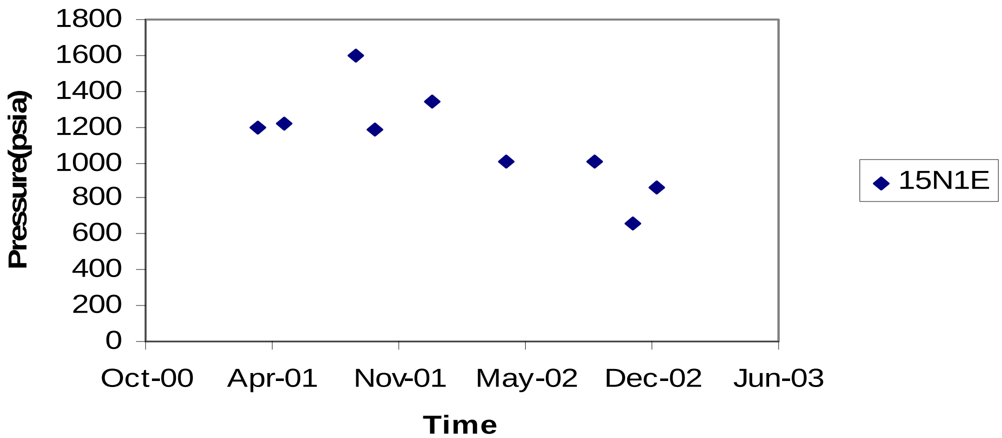

Figure 37: BHP vs. Time for West region

Due to the decrease in pressure it can also be seen that the amount of water produced also decreased (Figure 38) which further proves that the reservoir pressure of West Carney has considerably reduced.

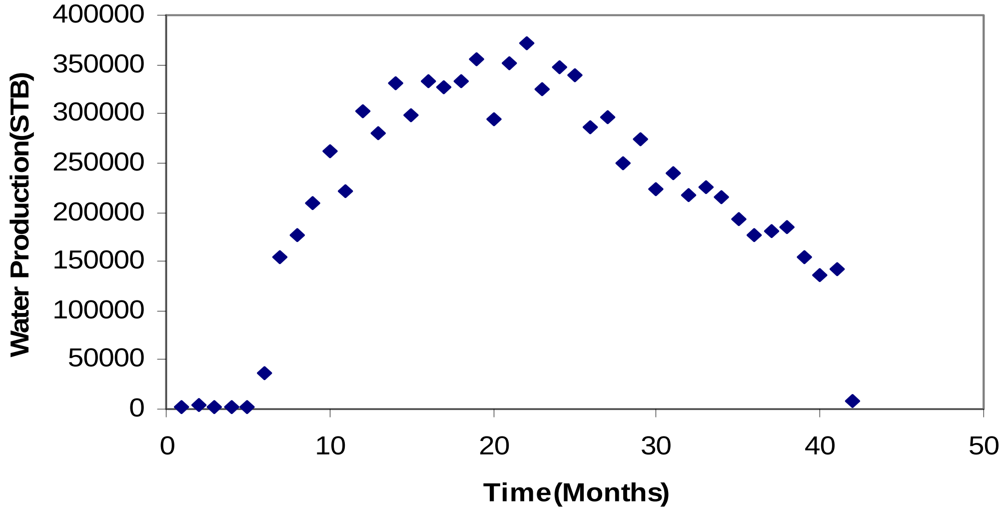

Figure 38: Water production vs. Time for West region

Plot of gas reserves (Figure 39) and oil reserves (Figure 40) with time show that West Carney does show a decline in recovery with time.

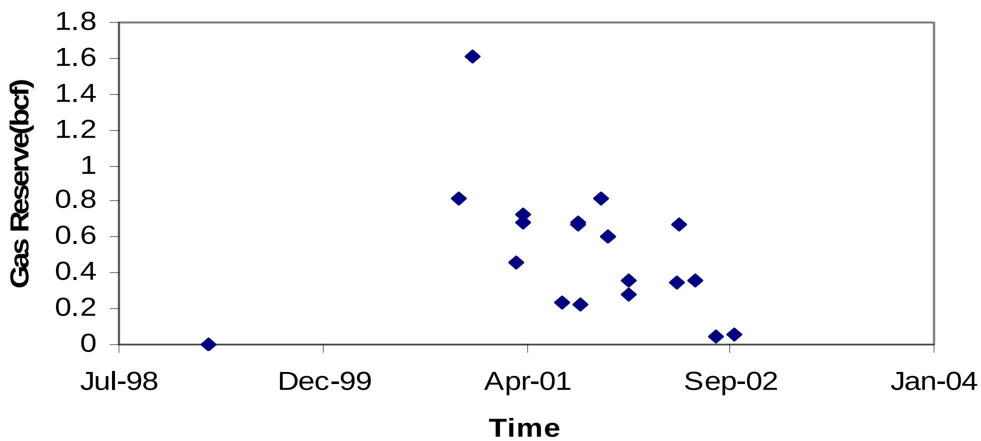

Figure 39: Gas reserves vs. Time for West region

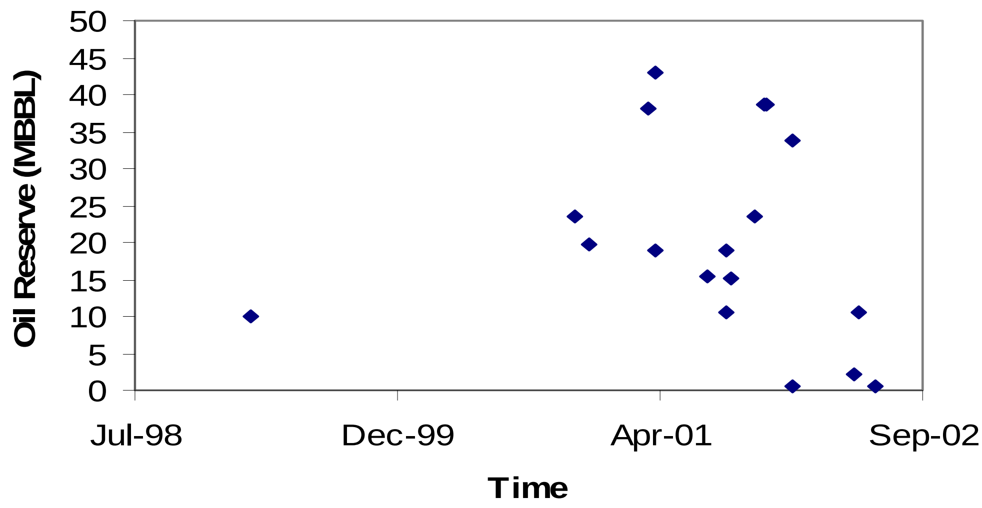

Figure 40: Oil reserves vs. Time for West region

From the above plots it can be concluded that reserves for West Region are strong functions of reservoir pressure. In other regions, recoverable reserves depend on the section were they are drilled, well density in that particular section, IP of the well which defines the preferential flow of fluids to the well bore and hydrocarbon saturation at well location. If a particular section has high well density then the recoverable reserves will be less. So location and well density plays an important role in the amount of recoverable reserves from a particular well. IP and hydrocarbon saturation are also important factors which will affect the recovery from a well.

Material Balance

This section discusses the method used to calculate recovery factors for oil and gas and the determination of final oil and water saturations at the time of abandonment. The method described here uses material balance and is applied individually to each of the four regions in West Carney. Final water saturation is calculated using gas recovery factor and compared with that obtained from cumulative water production. The comparison helps in validation of the material balance method. We first define the nomenclature.

Nomenclature

A = Section Area, acres

h = Thickness, ft

ϕ = Porosity

S_{wi} = Initial water saturation

S_{wf} = Final water saturation

S_{of} = Final oil saturation

R_{si} = Initial gas-oil ratio, SCF/STB

B_{oi} = Initial oil formation volume factor, bbl/STB

P_a = Abandonment Pressure, psia

R_{sa} = Abandonment gas-oil ratio, SCF/STB

B_{oa} = Abandonment oil formation volume factor, bbl/STB

B_{ga} = Abandonment gas formation volume factor, bbl/SCF

Where subscript i represents the initial condition and subscript a represents the abandonment condition.

Material Balance

It is assumed that initially there is no free gas present in the reservoir. Using the above nomenclature,

$$\text{Initial oil in place} = \frac{7758Ah\phi(1-S_{wi})}{B_{oi}} \quad \text{STB} \tag{1}$$

$$\text{Initial gas in place} = \frac{7758Ah\phi(1-S_{wi})}{B_{oi}} R_{si} \quad \text{SCF} \tag{2}$$

$$\text{Remaining oil at abandonment} = \frac{7758Ah\phi S_{of}}{B_{oa}} \quad \text{STB} \tag{3}$$

$$\text{Remaining gas at abandonment} = \frac{7758Ah\phi(1-S_{wf}-S_{of})}{B_{ga}} + \frac{7758Ah\phi S_{of}}{B_{oa}} R_{sa} \quad \text{SCF} \tag{4}$$

Ultimate oil recovery = $7758Ah\phi\left(\frac{1-S_{wi}}{B_{oi}}-\frac{S_{of}}{B_{oa}}\right)$ STB (5)

Recovery factor for oil = $\left(1-\frac{S_{of}B_{oi}}{(1-S_{wi})B_{oa}}\right)$ (6)

Ultimate gas recovery = $7758Ah\phi\left(\frac{(1-S_{wi})}{B_{oi}}R_{si}-\frac{(1-S_{wf}-S_{of})}{B_{ga}}-\frac{S_{of}R_{sa}}{B_{oa}}\right)$ SCF (7)

Recover factor for gas = $1-\frac{B_{oi}}{(1-S_{wi})R_{si}}\left(\frac{(1-S_{wf}-S_{of})}{B_{ga}}-\frac{S_{of}R_{sa}}{B_{oa}}\right)$ (8)

The initial oil in place is obtained from the geologic model of each region. The cumulative oil and gas production is obtained from decline curve analysis. Recovery factors for oil and gas are obtained by dividing the cumulative production by the in place amount. The final oil saturation S_{of} is obtained by substituting the oil recovery factor in Equation 6. The final water saturation S_{wf} is obtained by substituting the gas recovery factor in Equation 8. Table 11 shows the oil and gas recovery factors with final oil and water saturations at abandonment. The following values are used to perform the calculations:

P_a = 300 psia

R_{si} = 650 SCF/STB

B_{oi} = 1.316 bbl/STB

B_{oa} =1.076 bbl/STB

B_{ga} =0.009037 bbl/STB

R_{sa} = 70.33 SCF/STB

These values are based on an evaluation of oil properties based on the sample. The oil API gravity is observed to be 42 and the gas gravity is measured to be 0.72. The abandonment pressure can be varied; however, we assumed it to be 300 psia.

Table 11: Final Oil and Water Saturation from Oil and Gas Recovery Factor(MB)

Region	CE	CW	E	W
Initial Oil Saturation	**0.487**	**0.480**	**0.382**	**0.279**
Initial Water Saturation	**0.513**	**0.520**	**0.618**	**0.721**
Porosity	0.045	0.045	0.068	0.080
Oil in Place(MSTB)	25400	174380	53900	70630
Gas in Place(BCF)	16.520	113	35.035	46
Total Oil Production(MSTB)	2233	4534	2210	416
Total gas Production(BCF)	6.960	39.550	24.875	11.206
Oil RF	0.088	0.026	0.041	0.006
Gas RF	0.421	0.350	0.710	0.244
Final Oil Saturation	**0.365**	**0.384**	**0.301**	**0.228**
Final Water Saturation	**0.416**	**0.385**	**0.519**	**0.632**

Final Water Saturation from Water Production

The recovery factor for water is given by the following equation:

$$\text{RF (water)} = \left(1 - \frac{S_{wf}}{S_{wi}}\right) \tag{9}$$

Cumulative water production for each region was obtained by prorating the water production of Marjo wells by using the oil production values of Marjo wells only and the cumulative oil production of the entire region (production from all operators). Unfortunately, we did not have water production data available from all the wells. We had data from Marjo Production Company only. The initial water in place is obtained from the geologic model of the region. The recovery factor is calculated by dividing the cumulative water production by original water in place. Using Equation 9 the final water saturation S_{wf} is calculated. Table 7 provides the S_{wf} values obtained by using water recovery factors.

Table 12: Final Water Saturation from Prorated Water Production

Region	CE	CW	E	W
Water in place (MSTB)	35093	247474	114062	238869
Total Water Production (MSTB)	17665	54961	4868	27223
Water RF	0.503	0.222	0.043	0.114
Final Water Saturation	**0.255**	**0.405**	**0.591**	**0.639**

It can be seen that for the Central East Region the difference between the S_{wf} values obtained by the two methods is very large. The values for the remaining regions are in a close agreement. The close agreement between the two water saturation further validates our simplified material balance approach. One reason for the discrepancy in the values of the Central East region could be the uncertainty in prorated water production.

Adjusting Cumulative Water Production

The new water production values for the Central East, Central West and East regions were calculated by using the S_{wf} from gas recovery factors. By doing this, the final water saturation for each region at abandonment calculated by using the gas recovery factors is made to match the final water saturation calculated by water recovery factors.

Table 13: New Water Production to match Final Water Saturation from Gas RF

Region	CE	CW	E	W
Initial Oil Saturation	0.487	0.480	0.382	0.279
OOIP (MSTB)	25400	174380	53900	70630
OGIP (BCF)	16.510	113.347	35.035	45.909
Oil Production (MSTB)	2177	4430	2418	395
Gas Production (BCF)	6.953	42.548	19.500	12.493
Oil RF	0.086	0.025	0.045	0.006
Final Oil Saturation	0.365	0.384	0.300	0.228
Gas RF	0.421	0.375	0.557	0.272
Final Water Sat using Gas RF	**0.415**	**0.384**	**0.520**	**0.632**
OWIP (MSTB)	35093	247474	114062	238869
New Water Production (MSTB)	**6747**	**64495**	**18072**	**27223**
Water RF	0.192	0.261	0.158	0.114
Final Water using Water RF	**0.415**	**0.384**	**0.520**	**0.639**

The interesting information from Table 12 and Table 13 are the differences in cumulative Water Production. For the Central West Region, we had the most water production data. No adjustment is needed in that production to match water saturations using the two methods. For other three regions, we only had water production data from 7-8 wells. We extrapolated the data to all the producing wells by assuming that average cumulative WOR from Marjo wells is similar to other wells. This assumption may not be true and hence, it is quite possible that our extrapolated values are not accurate. In general, the data from this material balance exercise indicates that a simplified material balance is valid to understand the recovery from these types of reservoirs. The key assumption is that the majority of energy is provided by the expansion of gas coming out of solution gas drive.

Technology Transfer

No technology transfer activities were performed during this quarter.

Conclusions

Based on the material presented in this report, the following conclusions can be drawn:

- A surfactant, which can alter near well bore wettability, is identified. By increasing the gas relative permeability and reducing water relative permeability, the surfactant effectively increases gas water ratio. A potential near well bore treatment can increase the recovery of gas.
- The geological core descriptions, thin section analysis and conodont work for all the 27 wells is complete. Additional lithofacies as well as two new stratigraphic units are identified. A new geological model using this data is in progress.
- The recovery per well in Hunton reservoir indicates strong correlation with the spacing of wells. It appears that 160 acre spacing provides the best recovery per well in these reservoirs.
- The reservoir pressure as well as water production depletes with time in Hunton reservoirs. However, recovery per well is only observed to be a weak function of the reservoir pressure. This indicates that additional potential exists for drilling new wells in relatively depleted reservoirs.
- A simple material balance technique is able to explain many of the observations in the field. This technique can be used as a predictive tool in determining oil and gas ultimate recoveries in yet to be produced reservoirs.