FIELD REVIEW

Two Medicine Cut Bank Sand Unit (TMCBSU)

PHASE 2

prepared for

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1 EXECUTIVE SUMMARY

The objective of this review was to rapidly perform a production analysis, validate/identify existing or missing information and to recommend the next steps in the development of the Two Medicine Cut Bank Sand Unit (TMCBSU).

A brief summary of conclusions and recommendations for Phase 2 of the TMCBSU field review is given below. The report is divided into two main sections: I) Production Analysis and II) Operations Review, each discussed separately.

The production source data for this study was collected and prepared for analysis in a data acquisition phase (Phase 1) concluded on February 24, 2009. Production and injection data from two different sources, IHS Inc. and the Department of Natural Resources and Conservation (DNRC), was gathered and combined into one single database. The acquisition stage was followed by a thorough QA/QC process to ensure that the database was as complete as possible.

Production Analysis - The rapid production analysis was performed only on wells completed in the Cut Bank formation.

- Key Production Indicators for Candidate Reactivation Selection
  - Best 12 months of production
  - Last 6 months average production (oil & water)
  - Total fluid (oil & water) per foot of perforated interval
  - Historical well production and water-cut
- Field Overview
  - The northern part of the field recovered considerably higher oil production than the southern part. In particular, the Northeast area has had significant oil production (with relatively low water production), without receiving comparable volumes of water injection, indicating it could be the better reservoir the field.
  - The TMCBSU isopach map of 1972 is not representative of the production performance of the field, indicating that the petro-physical cutoffs (e.g. porosity, water saturation) utilized to allocate net versus gross pay may need to be redone.
- Candidate Recognition Results
  - The final candidate list includes 17 primary candidates and 10 secondary candidates. 6 of the primary candidates and 4 of the secondary candidates are current active wells, which leaves 11 primary and 6 secondary wells as the best wells to consider for reactivation.

Operations Review - The conclusions and recommendations for this section are mainly based on a two-day field visit to the TMCSBU the week of May 19, 2009, and on conversations with Arkanova and Provident representatives. Details are provided in Section 5.

Key recommendations from both sets of reviews are summarized below:

- Optimize operations and production from existing wells, and consider re-activating the candidates recommended in this review.
- Improve well testing capabilities to enable performance predictions
- Conclude gathering of missing field information (core studies, unitization agreements, PVT, reservoir studies, etc.) for complete well files
- Improve the geological understanding of the unit, validate oil-in-place and re-address the noncommercial nature of the upper Cut Bank sand.

- Conduct a dynamic waterflood evaluation to identify un-swept areas, and areas where the channeling is more (or less) severe
- Recommend digitizing logs for use in future studies
- Consider performing geological/reservoir simulation studies prior to initiating a drilling program (horizontal or infill) or a waterflood reactivation, to address reservoir uncertainties and to mitigate risks. Currently available information and engineering done to date is insufficient for recommending a long-term field development plan.

Schlumberger Data & Consulting Services appreciates the opportunity to deliver this preliminary field study (Phase 2) to Provident Energy Associates, LLC, and look forward to assisting with any future consulting needs.

2 DATA OVERVIEW

The source data used in this project was collected and prepared for analysis in a data acquisition phase (Phase 1) concluded on February 24, 2009. Well locations and basic well information (such as well name, operator, spud date, etc.) together with production and injection data was gathered from two different sources and combined into one single database. The two data sources used were IHS Inc. (online public database) and the Department of Natural Resources and Conservation (DNRC), Montana.

IHS did not have a complete dataset for the TMCBSU, so it was complemented with information gathered from the DNRC. In particular, the IHS dataset included only 83 of a total 236 TMCBSU completions, and it did not have "early time" production data (from the 1960s) or any injection data for the waterflood program implemented during the period 1968-1986. This is critical information for a production analysis study and was, therefore, gathered from the DNRC office in Billings, Montana. Some basic well information was found and downloaded from DNRC's online database, but the actual production and injection data was collected (scanned) from hard copy reports filed with the DNRC. It was brought back to Houston and manually entered into Excel for preparation and entry into the project database (Access) and production analysis tool (OFM – a Schlumberger software).

Figure 2.1 illustrates the data acquisition phase, with data from two sources combined into one single database. IHS provided production data from 1978 to 2008, and injection data for two disposal wells from 1996 to 2008. DNRC provided production data from 1960 to 1978 and injection data (waterflood) from 1968 to 1986. The production data from September 1960 to October 1968 and from June 1978 to May 1983 is lease data (not per well data) and represents estimates only.

In addition to the publicly available information (IHS and DNRC), a working project database will be complemented with information found in well files, as indicated by the grey box in Figure 2.1. This step was included in Phase 2; but as discussed later in this report, it proved challenging to gather additional information in particular, reservoir and petro-physical information and individual well history, such as completion equipment and previous workovers.

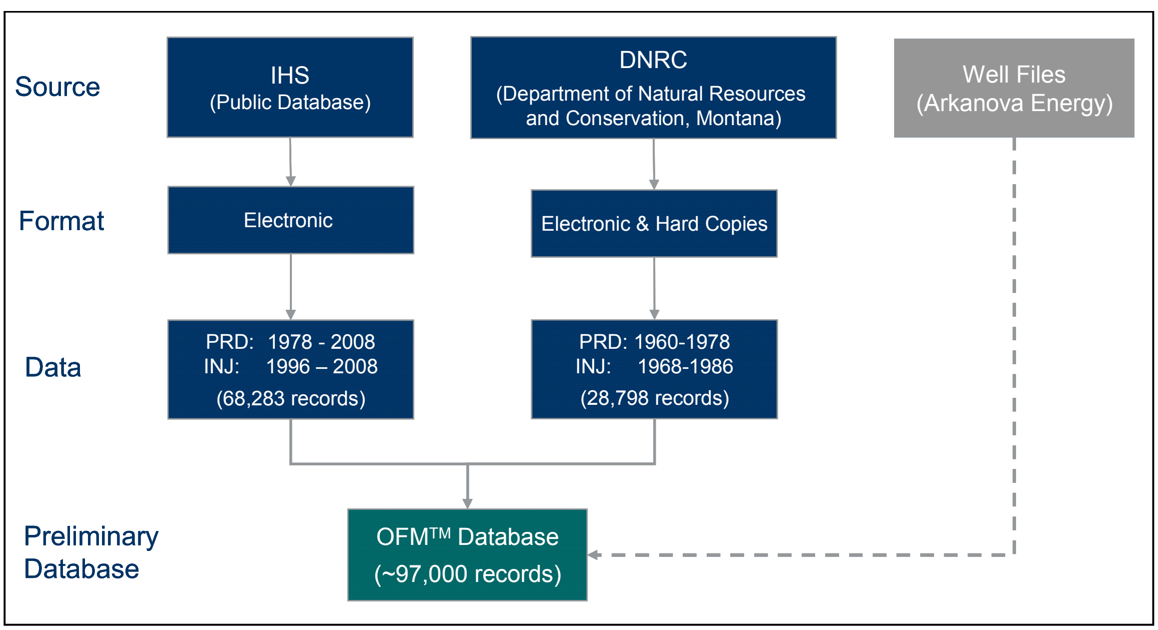


Figure 2.1: Phase 1 (Data Acquisition) data sources.

The acquisition stage was followed by an extensive Quality Assurance and Quality Control (QA/QC) process to ensure a high-quality database for use in Phase 2. Merging two sets of data presents several challenges, one of which is duplication, so great care was taken in building the final well inventory and in matching the production and injection data to the correct well.

The production and injection data (provided by DNRC) was assigned to a particular well by well name, not API or another unique ID. The well inventory was therefore build based on well-names and locations (xy coordinates), with the API as a second reference. Note that the four digit naming convention used in this study (e.g. 01-09, 26-09, 33-15) was adopted from the old production reports. The first two digits represent the section the well is located in, and provided a good way to check its location versus the location indicted on the isopach map.

Some assumptions had to be made in this process. For example, one well was downloaded from IHS with the well name “2D”. This well was matched to TMCBSU by its xy coordinates and renamed to “34-06” by the fact that it had the same API and location as the 34-06 well found in the DNRC database. Other assumptions and issues regarding Phase 1 are given in the Appendix.

3 TMCBSU FIELD OVERVIEW

3.1 Location

The Two Medicine Cut Bank Sand Unit (TMCBSU) is located in northwestern Montana, on the border of Glacier and Pondera County (Township 31-32N and Range 6W). It forms the southwest corner of the larger Cut Bank field. Part of the unit is within the boundary of the Blackfeet Indian reservation. Figure 3.1 and 3.2 illustrate the location of TMCBSU[1]

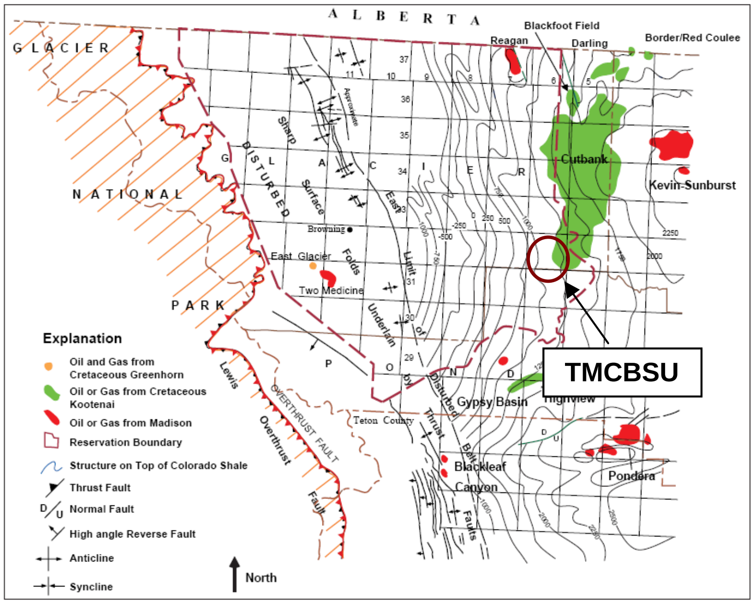


Figure 3.1: Cut Bank Field.

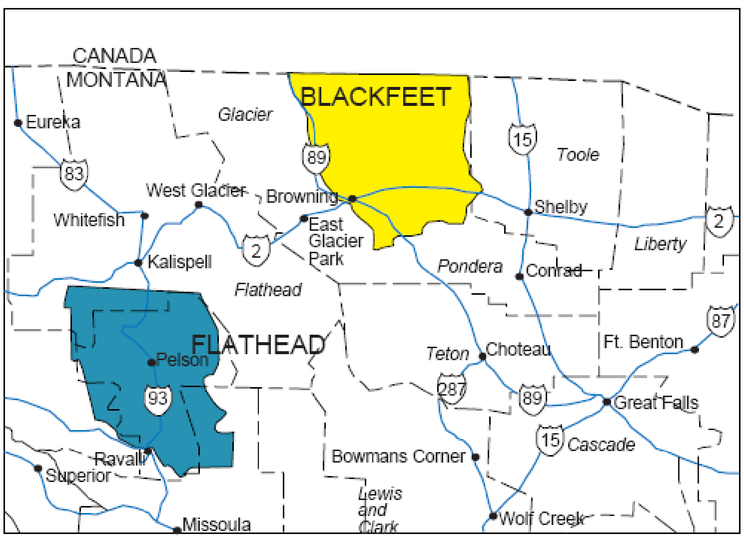


Figure 3.2: Blackfeet Indian Reservation.

The unitization of the Two Medicine Cut Bank area was commenced in 1965, by Continental Oil Company, and made effective August 1967. The current configuration was made effective in 1972, under Miami Oil Producers, Inc.[2] The unit boundaries are outlined on an isopach map from 1972, shown in Figure 3.4.

3.2 Well Inventory

The field has been in production since the early 60s, with an active waterflood from 1968 to 1986. The majority of the injection wells were drilled and completed for that purpose, with only 11 wells converted from producers to injectors. There are a total of 233 completions in the Cut Bank formation and 3 completions in the Madison formation, below the Cut Bank zone. All active wells are currently producing from the Cut Bank formation. The well inventory with regards to well status is as follows:

Cut Bank Formation

16	Active Producers (data source: 12 active wells; 4 additional wells confirmed by operator)
72	SI or TA Producers (data source: 76 SI or TA wells; 4 wells re-defined as active)
31	P&A Producers
104	P&A Injectors
10	Dry Wellbores (or completions without production or injection data)
233	**Completions**

Madison Formation

1	SI Producer (5994)
2	Disposal Wells (5991: active & 5993: P&A)
3	**Completions**

Two additional records (08-06 & 27-20) were downloaded and included in the final database for completeness, but they are defined as "Expired" (location or permit) without a defined location (no xy coordinates) and, as such, do not represent an actual wellbore or completion.

The TMCBSU database inventory (Figure 3.3) was confirmed against the isopach map provided by the client (Figure 3.4). A complete inventory list is given in the Appendix.

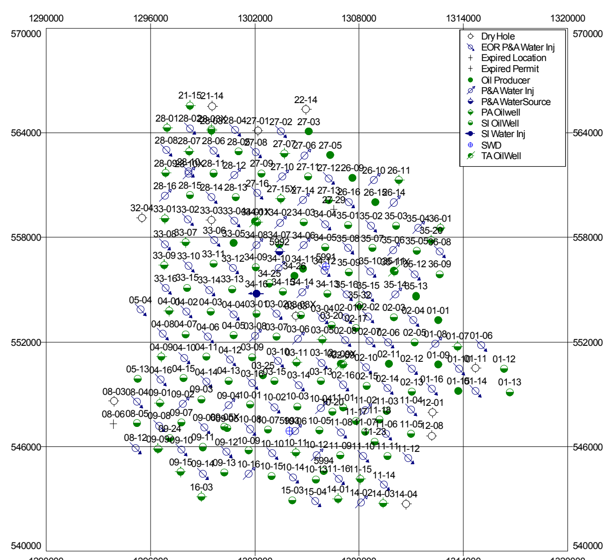


Figure 3.3: OFM™ Base Map.

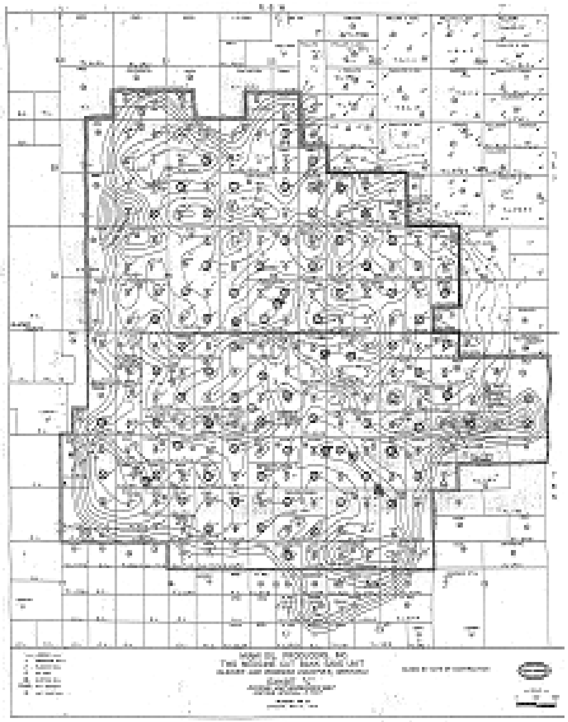


Figure 3.4: Isopach Map (1972).

3.3 Field Production

3.3.1 Cut Bank Formation

The current field production is approximately 38 bbl/day of oil and 271 bbl/day of water. Associated gas is considered too small to measure and is vented to surface or consumed as fuel.

The cumulative oil and water production from the Cut Bank formation, over the life of the field, totals 10.48 MMbbl and 31.29 MMbbl, respectively. Total oil production represents about 1/3 of water production. Total water injection is 51.14 MMbbl (waterflood: 1968 – 1986).

Production and injection data on a per well basis was only available from 1968 onwards. Information prior to this date was reported by operator on a unit or lease basis. Both sets of data are included for a complete picture, but the lease figures represent estimates only. Figure 3.5 shows the resulting cumulative production and injection history for TMCBSU in the Cut Bank formation.

CUT BANK FORMATION

Production (per well)		**+ Lease Prd**
Oil Cum:	7,748 Mbbl	2,733 Mbbl
Water Cum:	22,595 Mbbl	8,700 Mbbl
Gas Cum:	2 MMscf	

TOTAL Production

Oil Cum:	10,481 Mbbl
Water Cum:	31,295 Mbbl
Gas Cum:	2 MMscf (well 04-11 only)

TOTAL Injection
Injection Cum: 51,143 Mbbl (excl. disposal)

Note:

Total oil cum of 10.5 MMbbl is within 3% of total cum estimated by BLM, indicating a successful data acquisition phase. BLM estimated a total cum of 10.6 MMbbl (through March '95), while today's estimate is given as 10.8 MMbbl (Arkanova 2008 Annual Report)

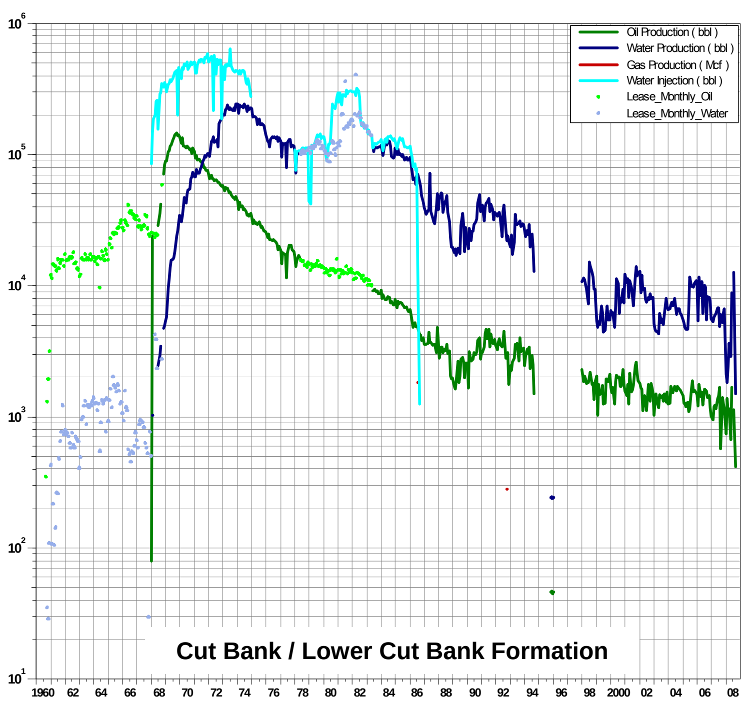


Figure 3.5: Total TMCBSU Production & Injection (Monthly Rates).

3.3.2 Madison Formation

The cumulative field production and injection for the Madison formation is given in Figure 3.6. The total production of 37 Mbbl oil and 1.7 MMbbl water comes from one well only (well 5994). In addition to the one producer, two disposal wells are completed in the Madison formation, one P&A (5993) and one currently active (5991).

MADISON Formation:

TOTAL Production (5994)
Oil Cum: 37 Mbbl
Water Cum: 1,667 Mbbl

TOTAL Disposal (5991 & 5993)
Injection Cum: 966 Mbbl

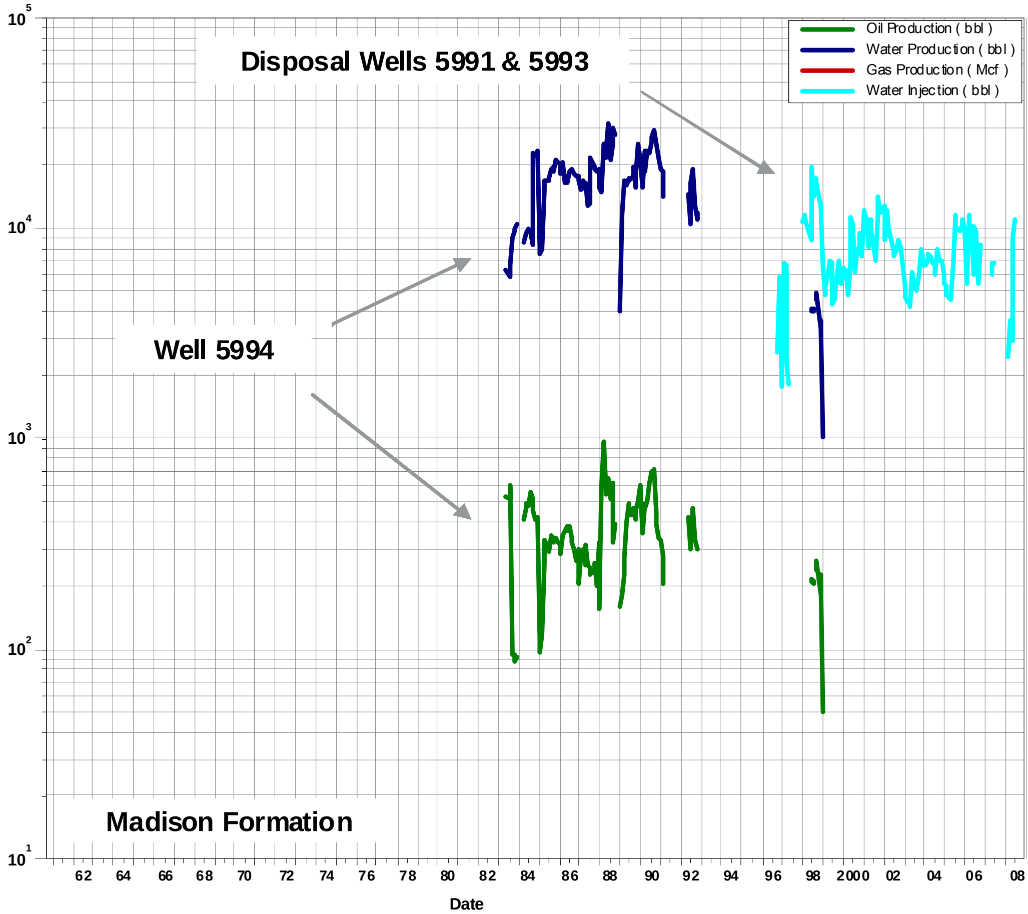


Figure 3.6: Total TMCBSU Production & Injection (Monthly Rates).

3.4 Reserves Estimates (Ref.: 1996 BLM Study)

Reserves estimates are outside the scope of this study. However, in order to put this study in perspective, a few figures from a 1996 Bureau of Land Management (BLM) report are discussed here. We do not confirm or challenge these estimates at this time.

BLM estimated the original oil-in-place (OOIP) to be 105.39 MMbbl, assuming an average porosity (Φ_{avg}) of 12.7%, a water saturation (S_w) of 30% and a formation volume factor (B_o) of 1.1 resbbl/STB. Primary recovery was estimated at approximately 7.7%., but considering an active waterflood, BLM concluded that a recovery factor of approximately 26% could be achieved. With a 10% recovery to date (10.8 MMbbl oil), this leads to potentially recoverable volumes of 16-17 MMbbl oil. However, it was stated in the BLM study that achieving this number was “unlikely”, due to the fact that all the injection wells had been P&A’d and re-establishing an effective injection system or another form of secondary recovery system, may not be economical.

3.5 Geology & Reservoir Properties

Due to limited available information regarding reservoir and petro-physical properties, this section gives only a brief overview of the Cut Bank formation. It is based on an isopach map and a structure map, see Figure 3.7, in addition to the BLM report from 1996 and publically available information, in particular an article from the Blackfoot Nation. Larger versions of the two maps are given in the Appendix.

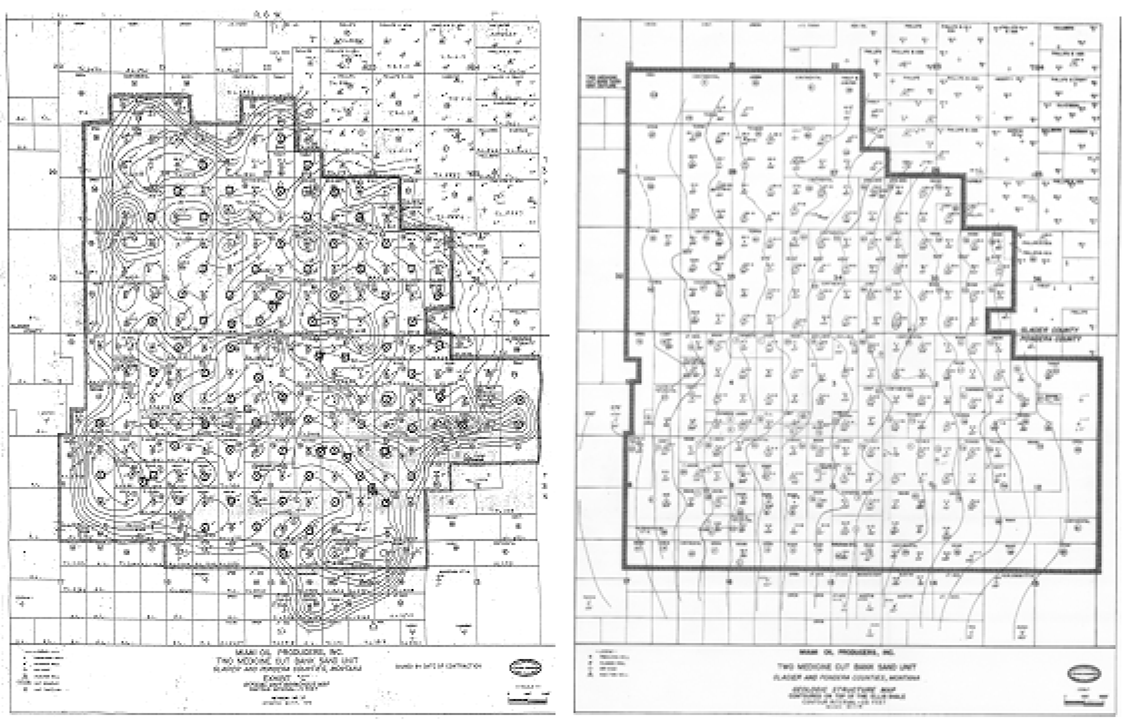


Figure 3.7: TMCBSU Isopach map and Structure map.

As mentioned in Section 3.1, the TMCBSU is located on the southwest corner of the larger Cut Bank field. The geological structure is a monocline, situated on the west side of Sweetgrass Hills Arch. The formation dips west at approximately 100-70 ft/mile. In other words, the “updip” part of the formation is in the southeast. Basic cross-sections based on well logs are given in Figures 3.8 through 3.11.

Another simple way to visualize the formation is to color code the isopach map and the structure map for a quick look at the variations and locations of net pay throughout the field, as well as the updip/downdip part of the unit. Two such maps are given in the Appendix.

The cut bank formation is a cretaceous sandstone. Two sands have been identified; an upper, non-productive sand (0-38 ft thickness) and a lower oil bearing sand (0-47ft thickness). In BLM's report from 1996, the reservoir was described as "relatively clean, porous, heterogeneous, sand with little-to-no clay content". The report referenced early core samples for an average porosity of 12.7% and an average permeability of 44.6 md.

To better understand the formation and to be able to evaluate long-term field development opportunities, we recommend gathering information from previous core samples as well as obtain current fluid samples to confirm reservoir parameters, such as porosity permeability and PVT data. Secondly, we recommend building a geological model to validate volumetric calculations and to improve the understanding of the structure for optimized future well placements and/or secondary recovery processes. As a part of this model, it would be necessary to collect available logs or digitize paper logs currently at the DNRC office (Great Falls, Montana). It may not be economical to digitize all TMCBSU logs, so an alternative could be to select a few wells, evenly spaced throughout the field for an overall description of the unit or to focus on only one part of the unit.

3.5.1 Cross-Section: North to South

Figure 3.8 and 3.9 illustrate the updip southeast section of the field with a North-South cross-section based on logs, referencing sea level. Figure 3.8 shows the selected wells.

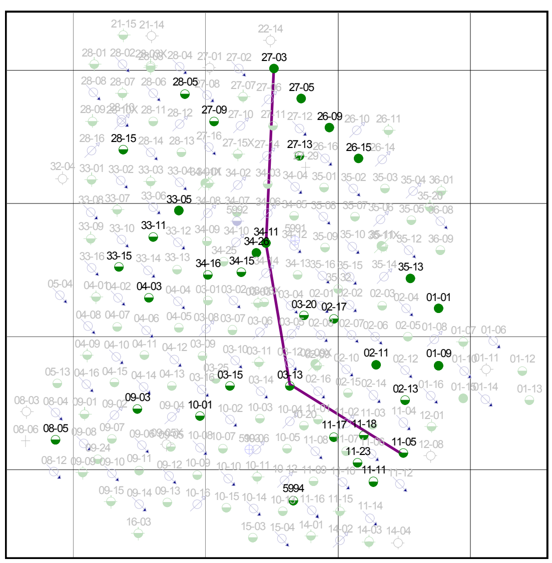


Figure 3.8: Cross-Section from North to South.

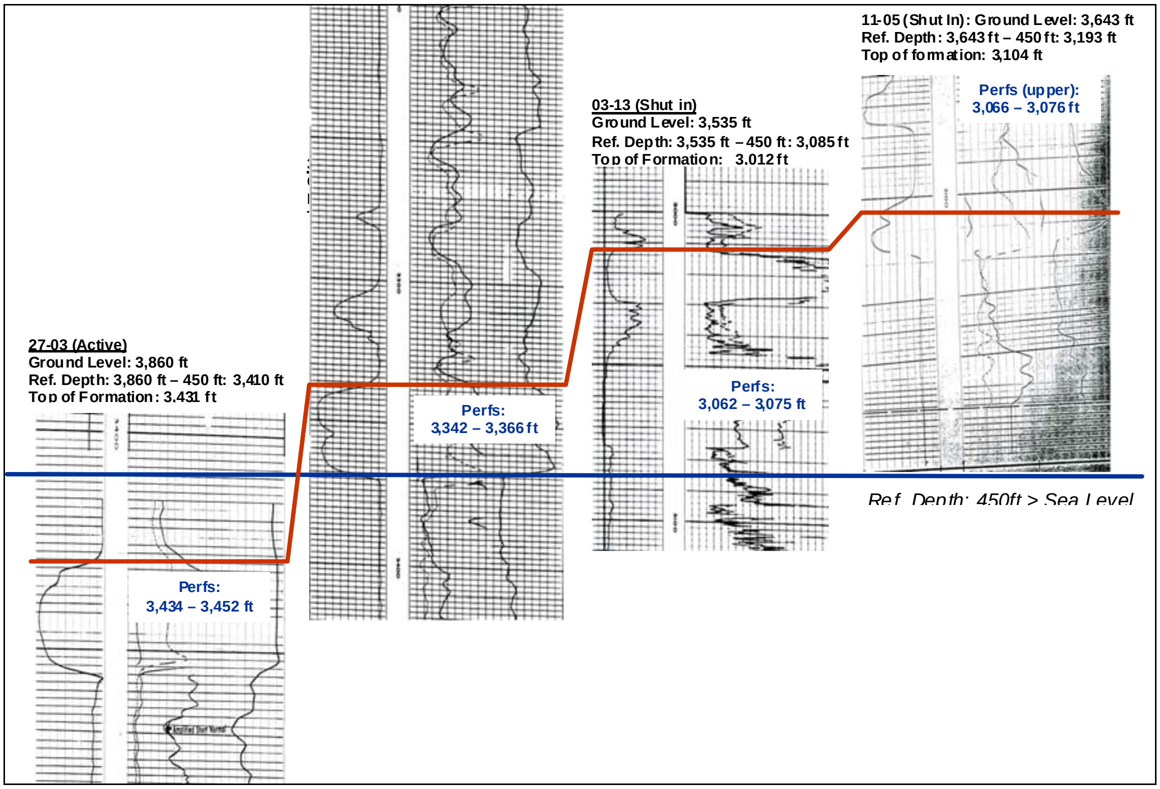


Figure 3.9: Cross-Section from North to South based on selected logs.

3.5.2 Cross-Section: West to East

Figure 3.10 and 3.11 illustrate the updip southeast section of the field, with a West-East cross section, again referencing sea level. Figure 3.10 shows the selected wells.

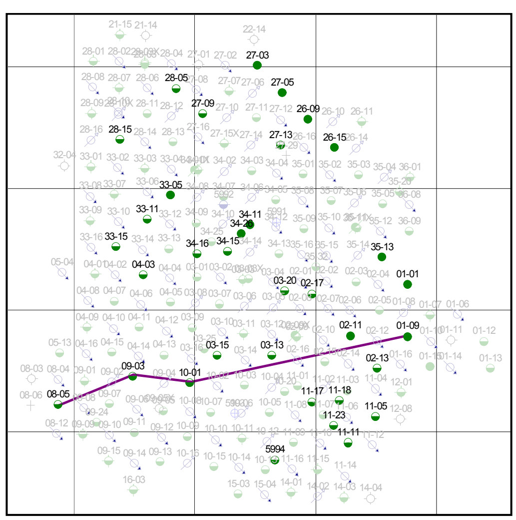


Figure 3.10: Cross-Section from West to East.

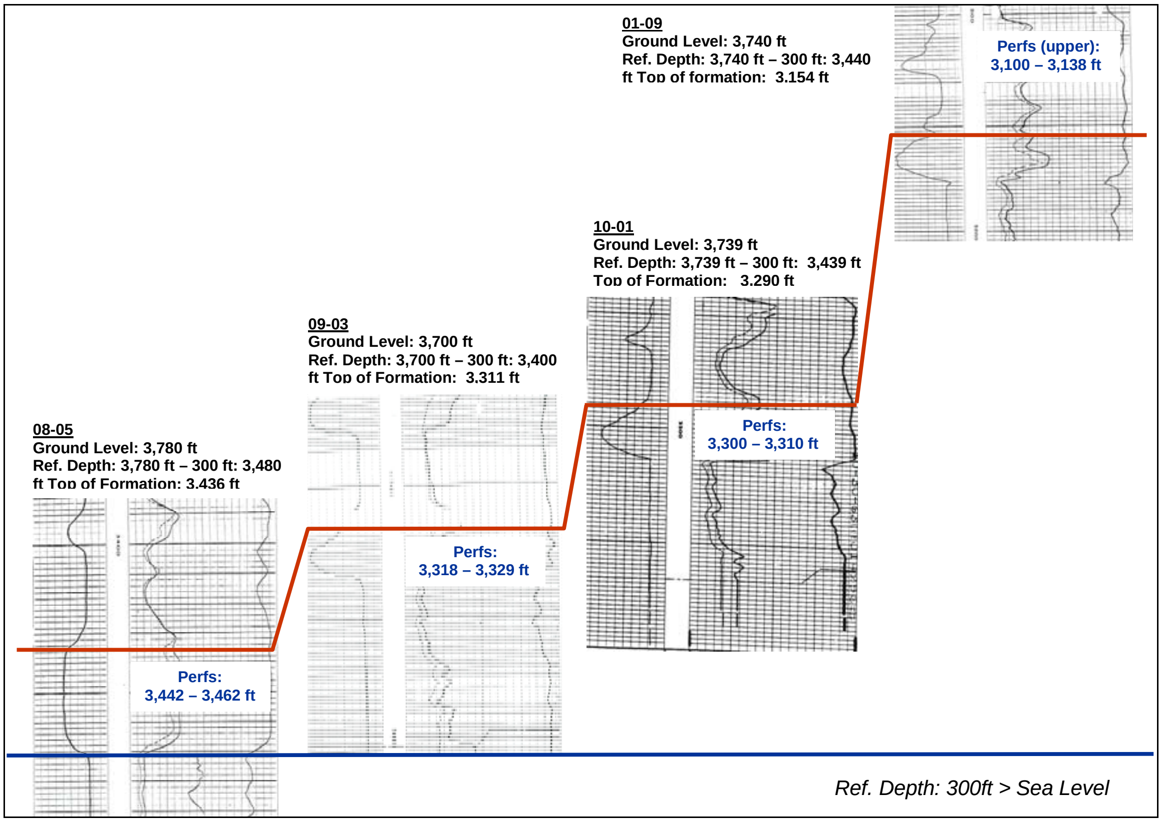
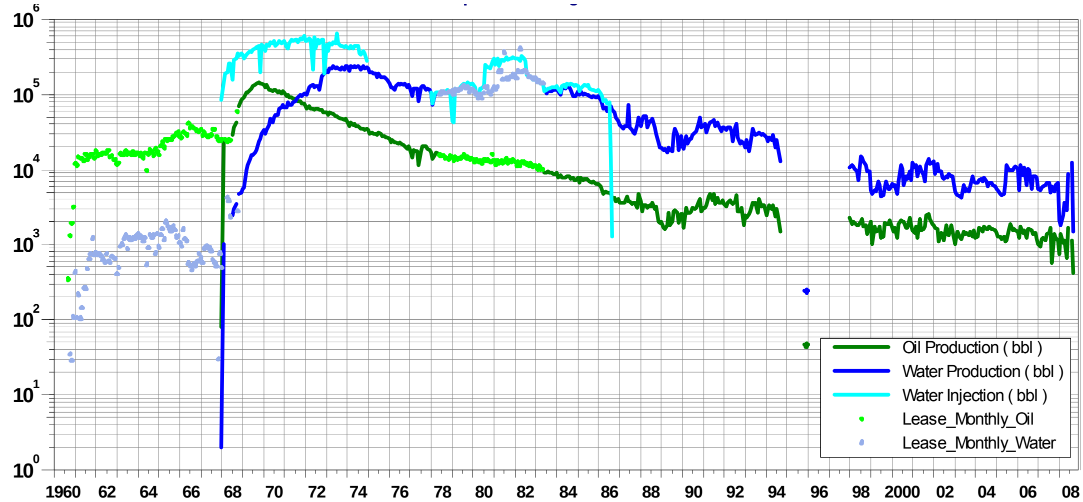


Figure 3.11: Cross-Section from West to East generated based on selected logs.

4 PRODUCTION ANALYSIS

4.1 Field Summary

Figure 4.1 represents the production and injection behavior and the evolution of the water cut with time. There is a drastic increase of field water production shortly after the beginning of the waterflood in 1968 (water cut eventually stabilizes around 85%). The oil production increased as well, but quickly tapered off and remained below that of water production throughout the life of the field, indicating potential channeling and poor waterflood sweep efficiency.



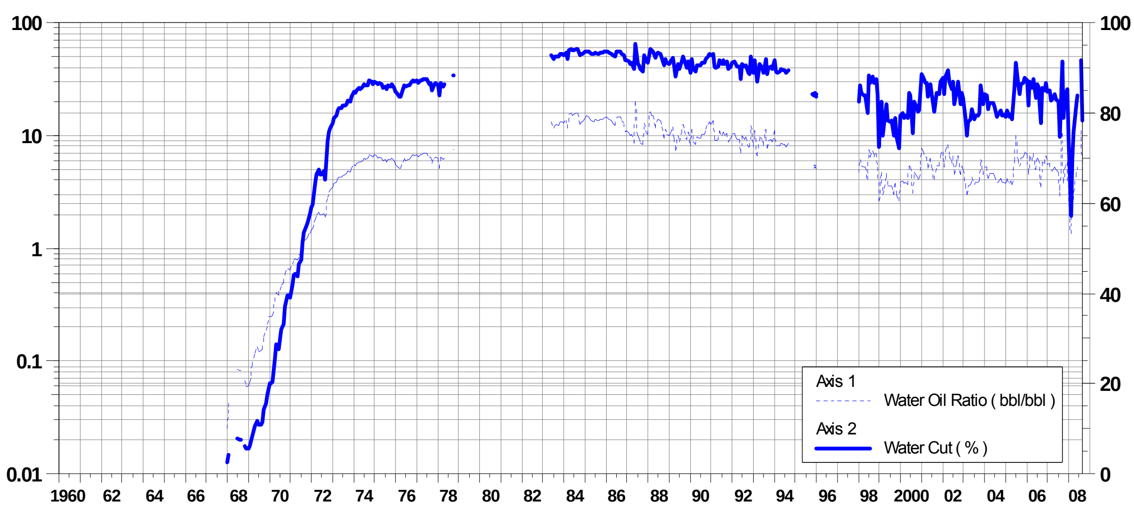


Figure 4.1: Top Graph: Total field production and injection. Bottom Graph: Water-cut & WOR.

Reviewing the field production and injection (Figure 4.1) with a well-count plot, five major events in the life of the field were identified (Figure 4.2):

1. The initial development of the field took place over three periods:
    a. 1959 to mid-1962 (Texota),
    b. 1964 to mid-1965 (Continental Oil Company) and
    c. 1965-1966 (Miami Oil Producers). A pilot waterflood was implemented in 1962. Unitization was commenced in 1965, and made effective in 1967. No completion count or per well production data was available for this period since production was reported at lease level.
2. In the second period, the full waterflood program was implemented. Water production increased drastically shortly after waterflood initiation ('68-'72). Oil production increased as well, but quickly tapered off. Fluid-In-Fluid-Out (FIFO) during the fill-up of the reservoir is around three.
3. In the third period, there is a drastic reduction of number of producers and injectors. 100 injector wells are P&A'd for economic and/or environmental requirements. There is a sharp oil production decline (FIFO has stabilized around 1).
4. In the fourth period, Mont-Mill Operating Company worked over several oil producers in the early '90s ('91 – '93). The production plot shows a significant increase in oil production without drilling additional wells. A review of the type of workovers done during this period can help evaluate potential workover opportunities.
5. In this last period, only 10 to14 producers were maintained active.

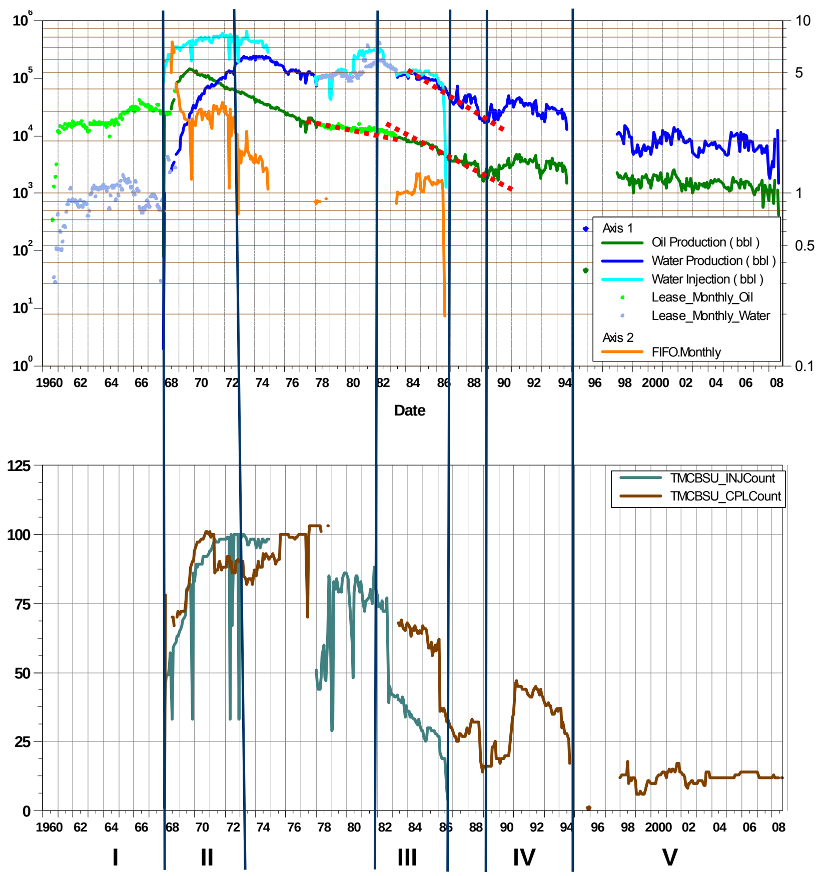


Figure 4.2: Top: Total field production and injection. Bottom: Production and injection well count.

A field review in terms of cumulative oil, water and water injection, as well as total fluid (oil & water) production per foot of perforated interval was conducted. The main objective for this review was to identify the best areas of the field and to gain a better understanding of overall field performance.

Figures 4.3 and 4.4 provide a visual representation of areas with high and low cumulative oil and water production in terms of bubble maps. The size of the bubbles represents the cumulative volume. Total oil production is approximately 1/3 of total water production over the life of the field. Areas of high cumulative oil production are indicated on the first plot (Figure 4.3), while areas of low water production are indicated on the second plot (Figure 4.4). These particular areas will be discussed throughout this section.

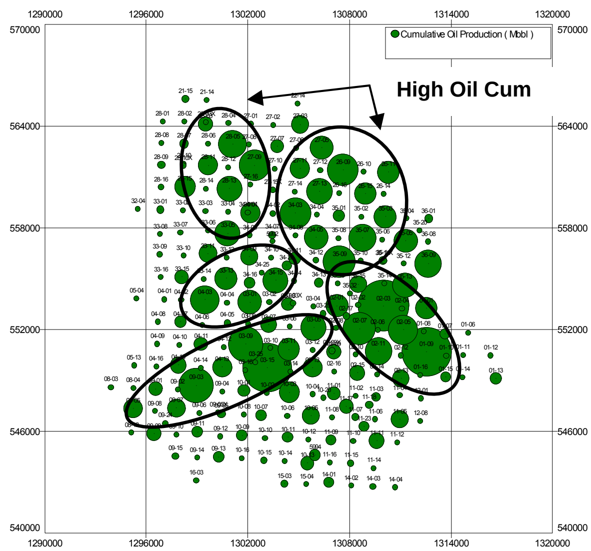


Figure 4.3: Cumulative oil production.

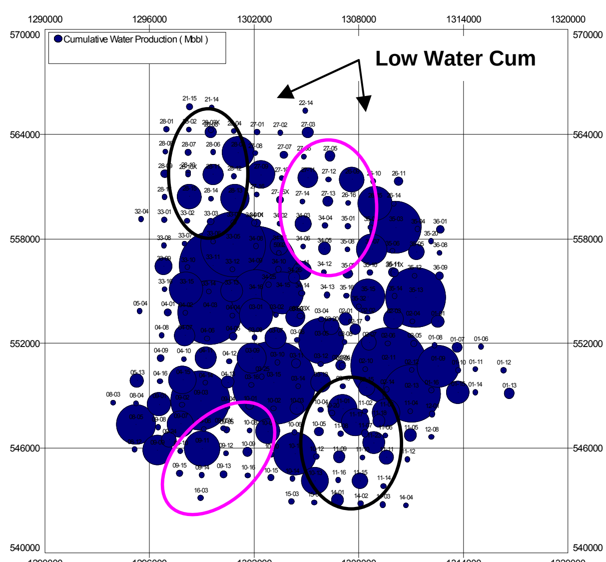


Figure 4.4: Cumulative water production.

Figures 4.5 and 4.6 show similar bubble maps of cumulative water injection. In this case, the size of the bubble describes the total water injection volume. Overall, produced water to injected water is approximately 2/3. The two plots below illustrate how the different areas of low water cum relate to water injection. Areas of low water cum corresponding with areas of low water injection are circled in Figure 4.5. The other two areas of low water cum circled in black (from Figure 4.4) correspond with high water injection volumes, Figure 4.6.

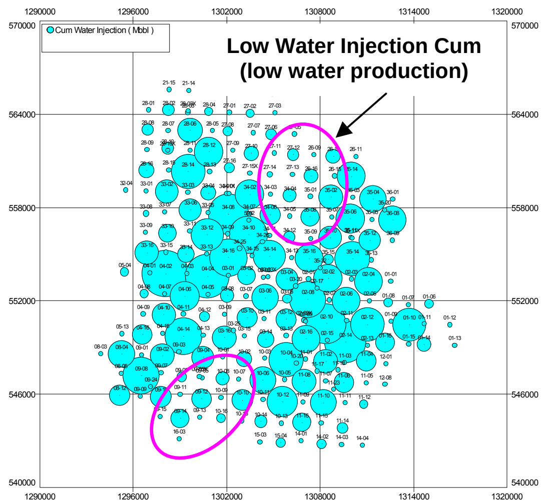


Figure 4.5: Cumulative water Injection.

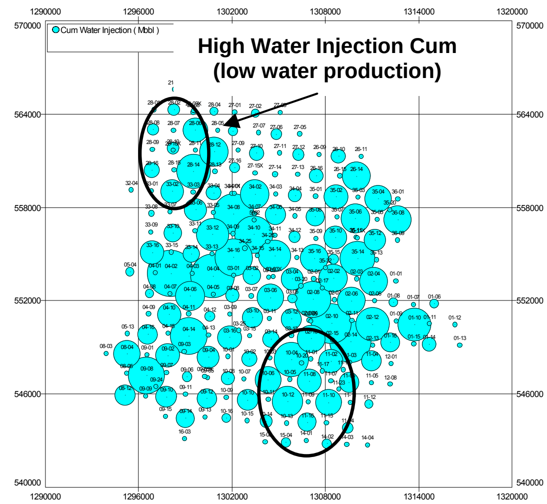


Figure 4.6: Cumulative water injection.

Furthermore, comparing all four regions with areas of high cumulative oil production in Figure 4.7 (and Figure 4.3), it is evident that the areas in the northern part of the field correspond with high cumulative oil production, while the southern areas correspond with low cumulative oil production.

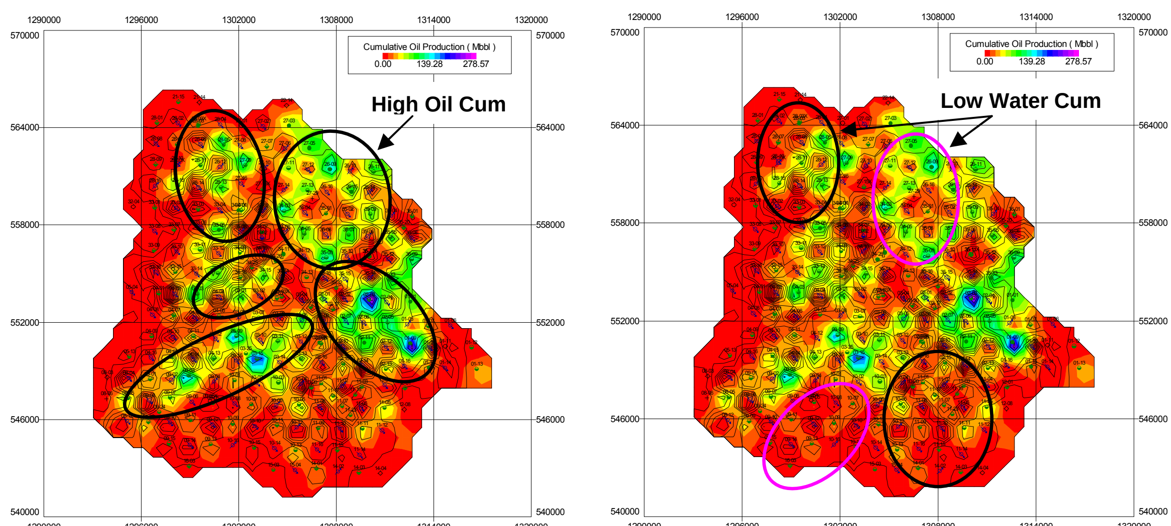


Figure 4.7: TMCBSU cumulative oil production, with contour map of cumulative water injection.

Figure 4.7 is a combination map, indicating areas of high total oil production (green and blue), but also areas of high water injection displayed as contours. When the contour intervals are closer, the water injection is higher. The high oil production areas circled in Figure 4.3 are also indicated on the first plot of Figure 4.7, while the low water production areas, discussed here, are indicated on the second plot of Figure 4.7.

Combining all this information results in four distinct areas as described below starting in the northeast section:

1. Northeast: High Oil Cum with Low Water Cum & Injection Cum.
2. Northwest: High Oil Cum with Low Water Production Cum, but relatively high Injection Cum
3. Southwest: Low Oil Cum with Low Water Production & Injection Cum
4. Southeast: Low Oil Cum with Low Water Production, but relatively high Injection Cum

It is worth noting that the Northeast section seems to be experiencing external pressure support, possibly from water-flooding outside the TMCBSU. Figure A7.5 in the Appendix, gives another water injection plot, similar to Figures 4.5 and 4.6 but with injection information on a few offset wells. These offset wells are not immediately close to the unit boundary but could potentially provide some of the pressure support.

Finally, Figure 4.8 adds one additional parameter, the height of the perforated interval. It represents only a rough estimate of a “productive” and “less productive” area of the field. The sections to the north have a medium-high perforated interval, while the areas to the south have perforated intervals considered small and medium.

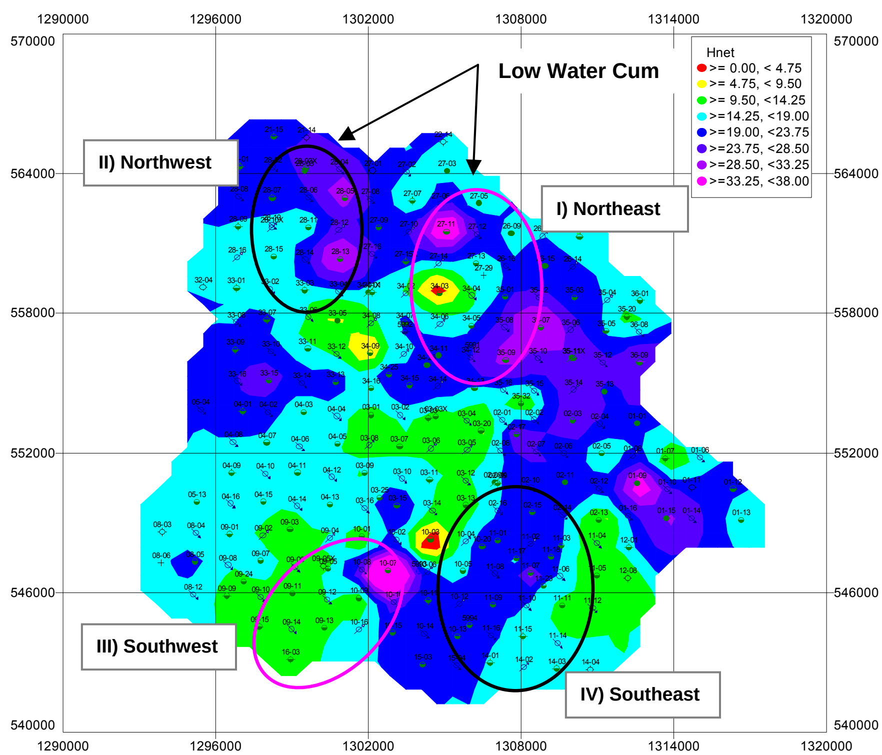


Figure 4.8: Map illustrating the height of perforated intervals throughout the TMCBSU.

The overall result is summarized in Table 4.1, which concludes the field overview, in terms of cumulative production and injection.

The better part of the TMCBSU, from a production analysis standpoint, is shown to be in the north, particularly in the Northeast section which seems to have some pressure support. The southern part of the field, on the other hand, does not perform as well. It is currently unknown why there is such a difference, but it could indicate poor rock quality or different reservoir properties than found in the north.

Table 4.1: TMCBSU Areas of High/Low Oil & Water.

Area	Oil Cum	Water Cum	Water Inj Cum	Perforated Interval
Northeast	High	Low	Low	Medium-High
Northwest	High	Low	High	Medium-High
Southwest	Low	Low	Low	Small
Southeast	Low	Low	High	Medium

4.2 Candidate Recognition – Production Indicators

To identify wells with significant potential, three production indicators were used:

The first production indicator, "Best 12 Months Average" (oil rate), correlates with the total cumulative oil production as well as with the first 5 years of production, see Figure 4.9 and 4.10. This means it is a good indicator for a well's short-term and long-term behavior and can be used with confidence to identify wells with the best potential.

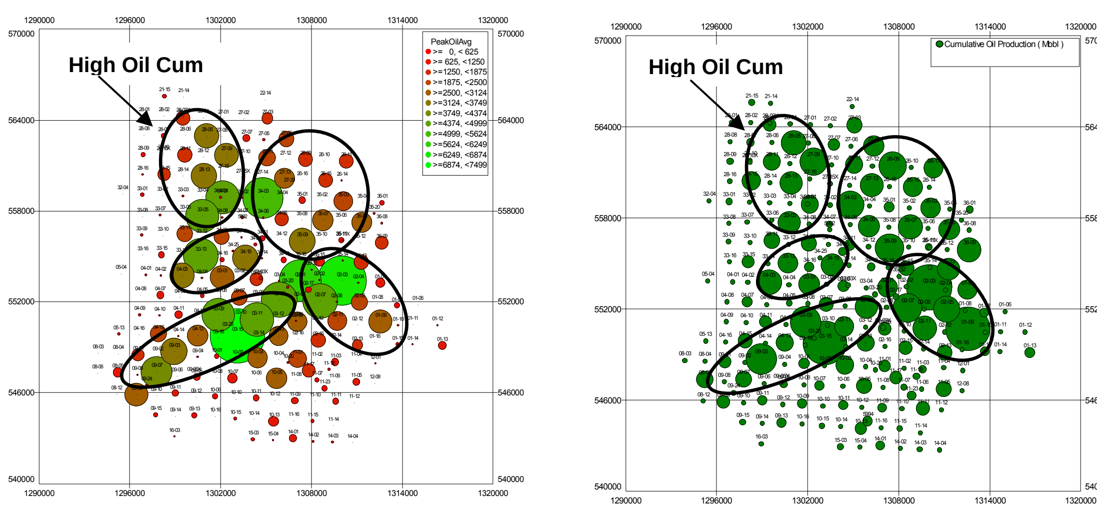


Figure 4.9: Best 12 months average oil rate (1st plot) corresponds with areas of high cumulative oil production (2nd plot).

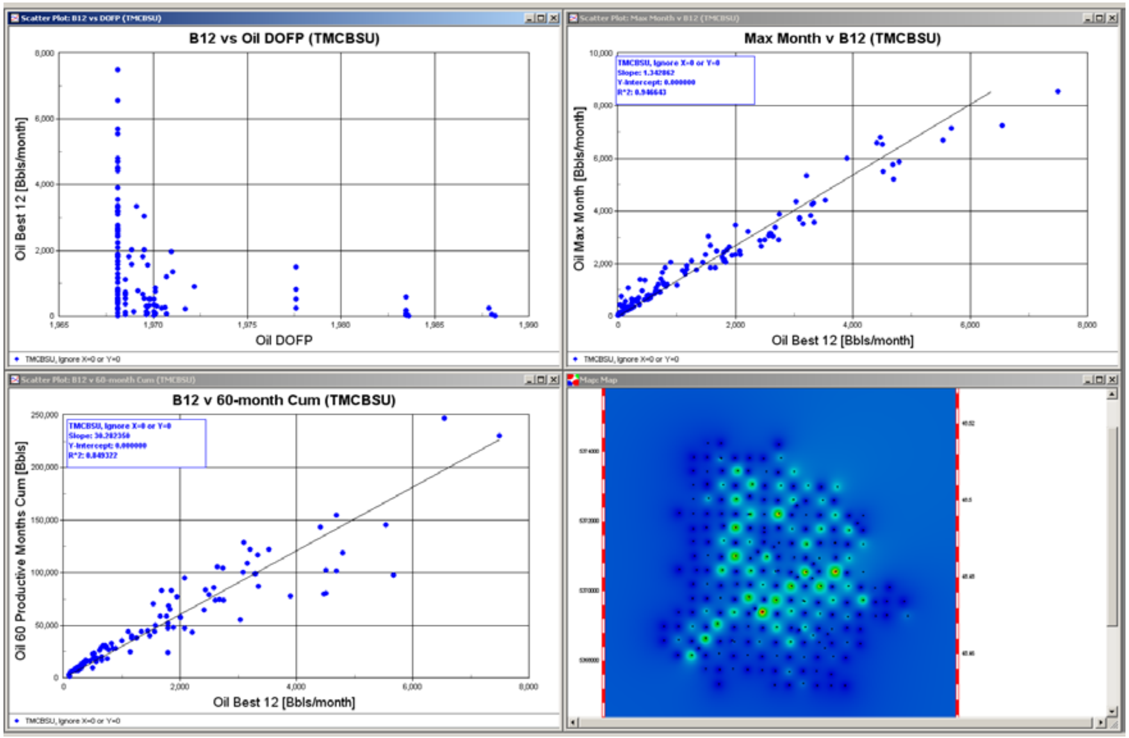


Figure 4.10: Best 12 months average oil rate vs. first 5 years cumulative oil production.

The second production indicator, "Last 6 Months Average" production rates (for oil and water) helps identifying wells that were shut down with high oil rates. Wells with high oil rates combined with low water rates represented the better candidates. Figure 4.11 illustrates the Last 6 Months Average results combined with water injection. The bubble map gives the last 6 months of oil production, while the color map indicates water production. The contours, as for Figure 4.7, indicate level of water injection. Only wells with an oil production greater than the mean were selected. This is explained in more detail in the next section.

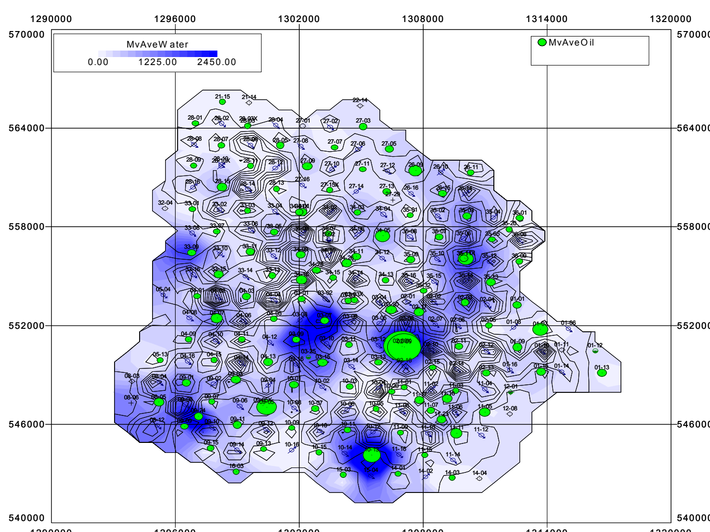


Figure 4.11: Last 6 months average (oil & water).

The third production indicator, "Total Fluid per foot of Perforated Interval" (last 6 months) was included to assess reservoir quality. It is represented in Figure 4.12. With limited petro-physical properties available, this analysis was added to better understand the productivity per foot of perforations. Nevertheless, this criterion can not replace geological and petro-physical studies.

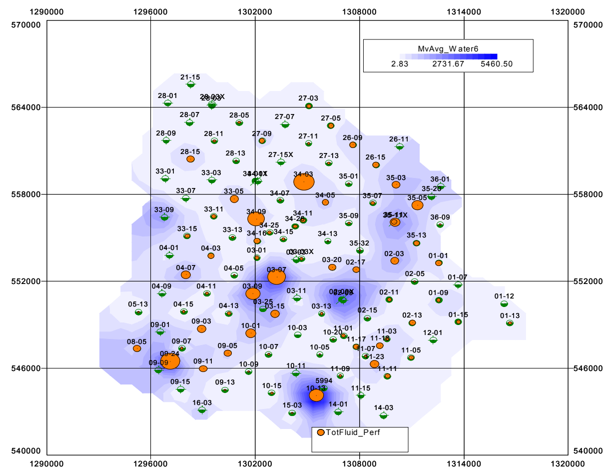


Figure 4.12: Total Fluid per ft of perforation.

In summary, the following selection criteria were used:

1. First Criteria: Best 12 Months Average Oil Rate (moving average)
2. Second Criteria: High Last 6 Month Average Oil Rate (above mean oil rate)
3. Third Criteria: High Last 6 Month Total Fluid per foot of Perforated Interval & water-cut < 90%

Candidates that matched all three selection criteria were then compared with the field's average production (oil/water) to ensure an overall good performance record, not just at the beginning and end of the well history. Furthermore, candidates were selected near high-water injection areas (past reactive waterflood areas) and in low-water production areas (low last 6 months average for water).

4.3 Candidate Recognition – Primary & Secondary Candidates

In terms of the first selection criterion, "Best 12 Months Average" (oil rate), a total of 48 wells with monthly oil production greater than 1,000 bbl of oil were considered as candidates. The list of all 48 potential candidates is given in the Appendix (Table A7.2).

In terms of the second criterion, "Last 6 Months Average" (moving average, oil and water rates), candidates were recognized based on their position relative to the mean oil rate. This is illustrated in the scatter-plot in Figure 4.13. The wells that are included in the first two quadrants have a "Last 6 Months Average" greater than the mean of 64 bbl/day and were considered potential candidates.

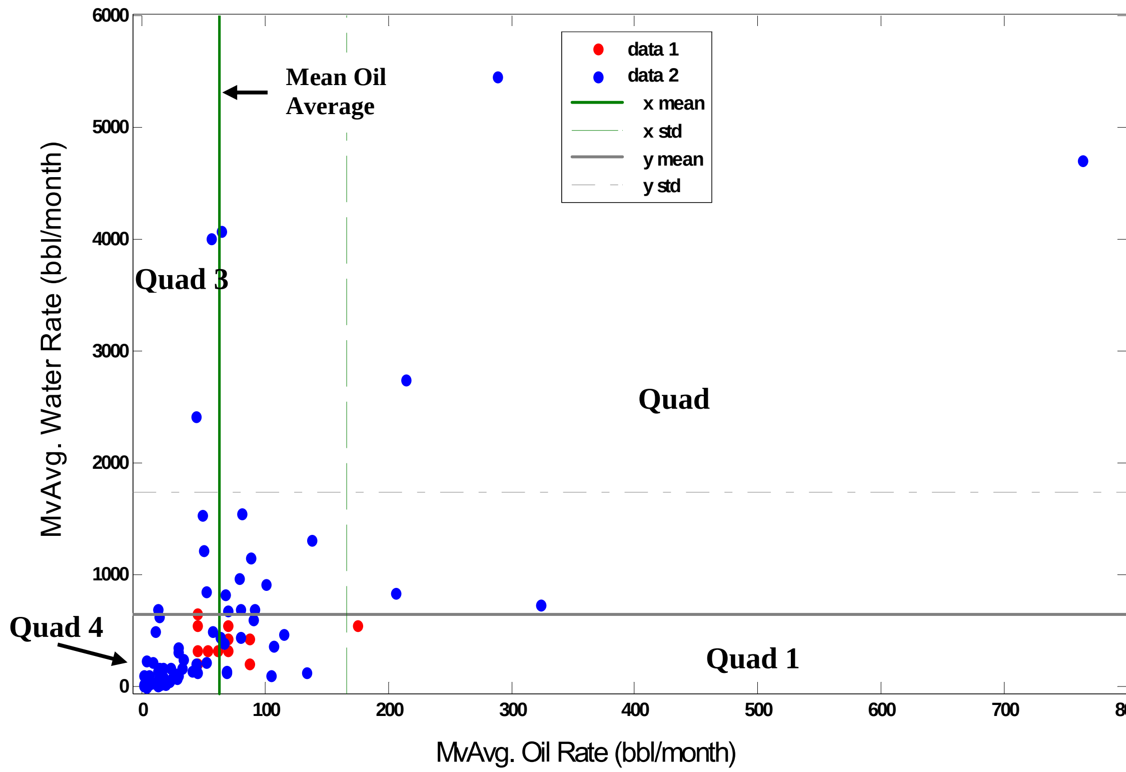


Figure 4.13: Scatter-plot between Moving Average of oil and water.

Based on the second criterion, a total of 30 candidates were selected. The complete list is given in the Appendix (Table A7.3). This list also indicates the category of the wells compared to the average. For example, "HOLW" represents a well that has an oil rate above the mean and a water rate below the mean. On the scatter plot it would fit in Quad 1. The explanation of the categories is also given in the Appendix (Table A7.4).

From the third criterion, "Total Fluid per foot of Perforated Interval", a total of 37 wells were selected. The cut-off was a liquid production per perforated interval greater than 11 bbl/ft. The complete list is given in the Appendix (Table A7.5).

When comparing all three lists (generated based on the three selection criteria), a total of 11 candidates were found to satisfy all three criteria. They are given in Table A7.6 in the Appendix. Apart from these candidates, wells that satisfied two out of three criteria were also considered possible candidates. Furthermore, the "Best 12 Months Average" (oil rate) method was shown to be a good indicator of the well potential, so wells that only satisfied this criterion were also considered as part of the first group of potential candidates.

As discussed in Section 4.2, a final selection filter was applied to the first group of potential candidates. The entire production history of each potential well candidate was studied and compared with the field average. The wells were then divided into four categories: HOHW, HOLW, LOHW, LOLW based on relative volumes of oil and water (e.g. HOLW = High Oil Low Water). This is the same terminology as for the Last 6 Months Average categories discussed earlier (and given in Table A7.4 in the Appendix) but based on historical production instead.

The final list of 27 candidates is given in Table 4.2 below, as well as in the Appendix (Table A7.7).

Table 4.2: Final list of selected candidates.

Well_List	MvAvg_Oil	Best 12 Months	Liq/ft Perf	Total	BLM	Historical Prd Behavior	Last Date Prd	Well Status OFM
02-11	0	1	1	2	X	HOHW	9/1/2008	OIL_ACT
03-15	1	1	0	2	X	HOHW	9/1/1994	OIL_SI
04-03	0	1	1	2	X	HOHW	8/1/1994	OIL_SI
08-05	1	1	1	3	X	HOHW	4/1/2002	OIL_SI
09-03	1	1	1	3	X	HOHW	4/1/2002	OIL_SI
11-17	1	1	1	3		HOHW	10/1/2002	OIL_SI
34-16	1	0	1	2	X	HOHW	12/1/2008	OIL_SI
01-01	0	1	1	2	X	HOLW	9/1/2008	OIL_ACT
01-09	1	1	1	3	X	HOLW	9/1/2008	OIL_ACT
11-05	1	0	1	2		HOLW	9/1/1994	OIL_SI
11-11	1	0	1	2	X	HOLW	8/1/1994	OIL_SI
26-09	1	1	1	3	X	HOLW	9/1/2008	OIL_ACT
27-05	0	1	1	2		HOLW	9/1/2008	OIL_ACT
27-09	1	1	1	3	X	HOLW	7/1/1994	OIL_SI
28-15	1	1	1	3	X	HOLW	8/1/1994	OIL_SI
34-05	1	1	1	3		HOLW	10/1/1978	OIL_SI
34-26	1	0	1	2	X	HOLW	9/1/2008	OIL_ACT
11-18	1	0	1	2		LOLW	8/1/1994	OIL_SI
35-13	1	1	1	3	X	LOHW	9/1/2008	OIL_ACT
26-15	0	1	1	2		LOLW	9/1/2008	OIL_ACT
02-13	0	1	1	2	X	LOHW	1/1/2008	OIL_SI
33-05	0	1	1	2	X	LOHW	9/1/2008	OIL_ACT
27-03	0	1	1	2		LOLW	9/1/2008	OIL_ACT
33-11	0	1	1	2	X	LOHW	10/1/2003	OIL_SI
02-03	0	1	0	1		NA	2/1/1986	OIL_SI
02-05	0	1	0	1		NA	6/1/1993	OIL_SI
27-13	0	1	0	1		NA	4/1/1994	OIL_SI

Bold Black : Primary Candidates

Bold Red : Secondary Candidates

Mavg_B12_Liq/ft

Mavg_B12

Mavg_Liq/ft

B12_Liq/ft

B12

In the table, binary indicators of 1 or 0 were assigned to each well for each of the three criteria, indicating whether or not a criterion was met (1 = met; 0 = not met). For example, well 08-05 satisfied the "Last 6 Months Average" criterion, the "Best 12 Months Average" criterion and the "Total Fluid per foot of Perforated Interval" criterion, resulting in a total score of 3, one for each criterion met. Similarly, well 03-15 satisfied only the "Last 6 Months Average" of oil and the "Best 12 Months Average" and received a score of 2, one for each.

As a reference symbol, 'X' was assigned to the wells based on if they had been recommended by the BLM in their report (Ditton *et al.*, 1996). This was done to compare the final candidate selection list with the list of wells BLM had recommended for workover or re-activation.

Additionally, the wells were color coded based on their production history behavior. Wells with oil production above average (either HOHW or HOLW) were considered to be primary candidates and marked in bold green (black in the table); whereas, wells with oil production below average (LOHW, LOLW) were considered to be secondary candidates and marked in bold red. A total of 17 wells were considered primary candidates and the remaining 10 were considered to be secondary candidates. The production curves for all 17 primary candidates are included in the Appendix.

The distribution of the primary and secondary candidates throughout the TMCBSU is shown in Figure 4.14. Among the 27 candidates, two candidates were recognized as extreme cases in terms of water and oil production which are marked. Well 26-09 had the highest oil production, while well 03-15 had the highest water production in the last 6 months.

Reactivation of primary candidates either in the Northeast part of near past reactive waterflood areas, where there is no significant water production, is recommended.

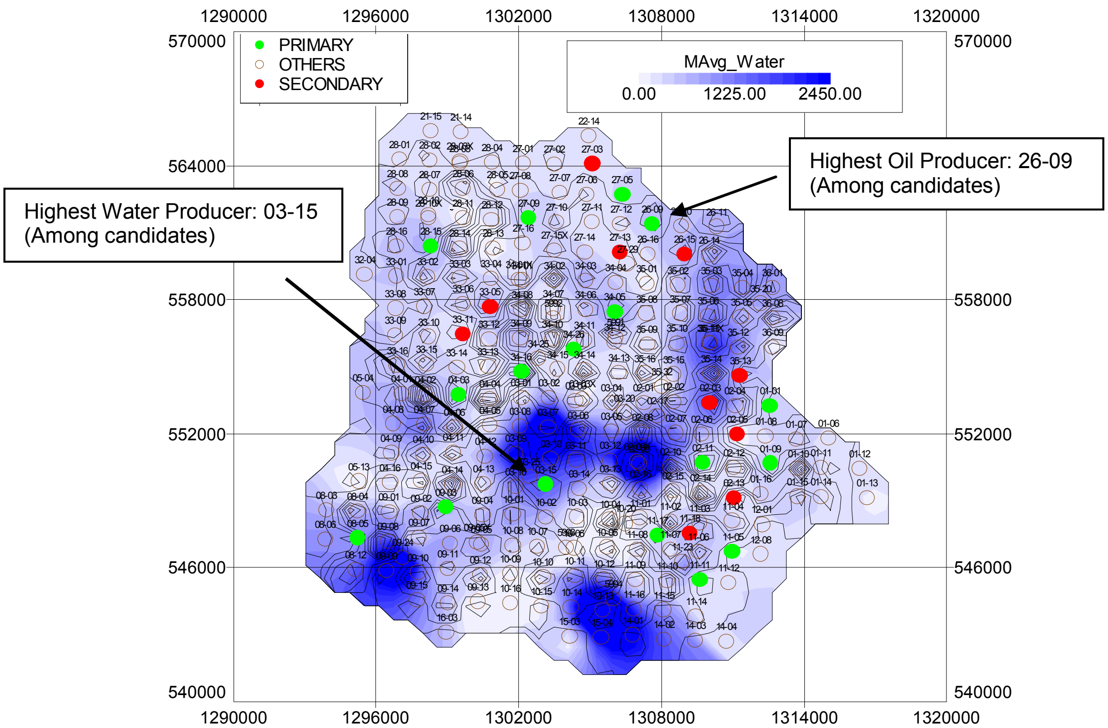


Figure 4.14: Location of primary and secondary candidates in the field.

5 OPERATIONS REVIEW

5.1 Field Status

This section is largely based on a field visit to TMCBSU the week of May 18, 2009 as well as on discussions with Provident and Arkanova representatives. The observations and the overall conclusions and recommendations tie in with the results of the production analysis.

There were 14 active wells on the unit at the time of the field visit, with two recently active wells down due to mechanical problems (27-03 and 34-16). Three wells were pending re-instatement, while another six were on the board for potential re-activations (five of which were recommended by BLM to be put back on production). All operations are on the north side of the Two Medicine River, where the only active battery is located (Battery 7). A schematic indicating current field status is given in Figure 5.1.

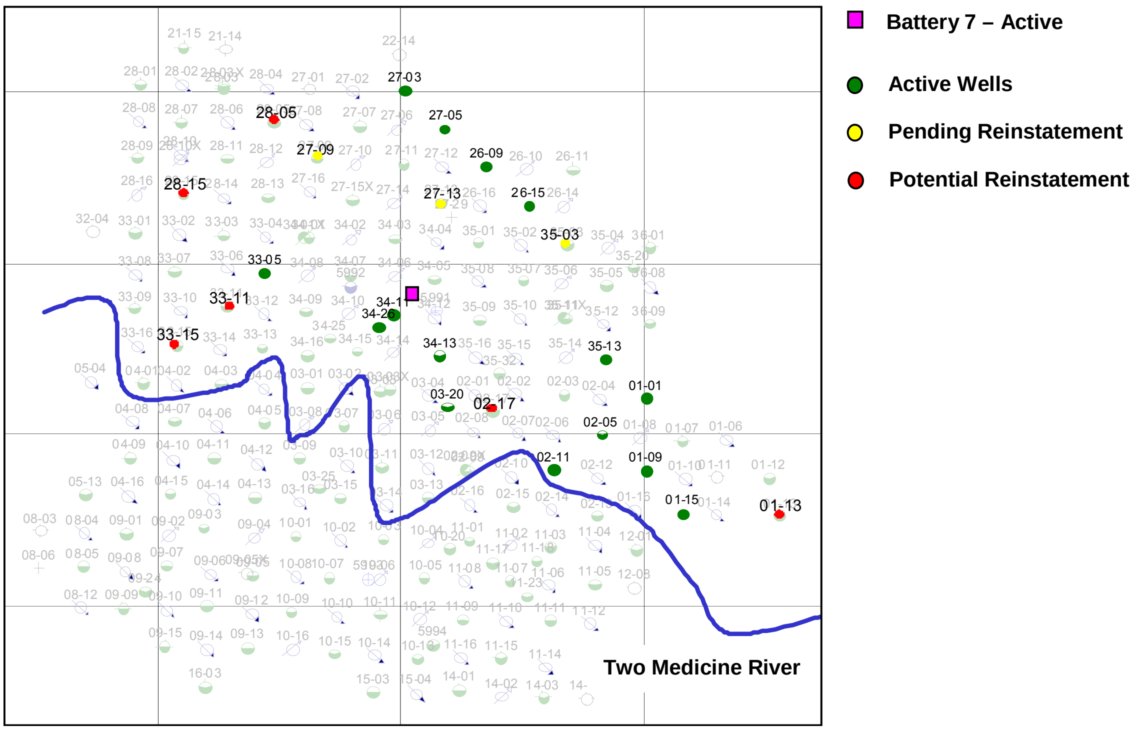


Figure 5.1: Schematic of TMCBSU, with active wells and wells pending re-activation.

The average production for the month of May (2009) was approximately 38 bbl/day oil and 271 bbl/day water. Associated gas is considered too small to measure and vented or consumed as fuel.

Recent fluid level measurements and the resulting calculated bottomhole pressures (see Appendix, Table A7.81) indicate that the reservoir is pressured up in several areas (1,400 – 1,600 psi), possibly maintained by waterflood operations in offset wells northeast of TMCBSU. Figure 5.2 gives a map of the TMCBSU, showing wells with fluid level information and their corresponding calculated bottomhole pressures.

The pumped off / low fluid levels and bottomhole pressures found for some of the active wells (26-09, 01-01, 27-03, 34-26, 34-11), indicate that they may have limited or partial communication with the reservoir. A review of past stimulation techniques is recommended. During the initial completions of the TMCBSU, a large spread of different techniques was utilized. This includes: hydrochloric acid only, smaller fracturing jobs with 3,000 gal of lease crude (LC) and 2,000 lb sand, and larger fracturing jobs with 20,000-30,000 gal LC + 20,000 lb sand. It should be re-emphasized that existing well files <u>do not reflect subsequent stimulation work performed after the initial completions.</u>

Additionally, in spite of the fact that the casing integrity of the active wells with fluid levels to surface needs to be investigated, it is important to ensure that these same wells be aggressively pumped prior to any repairs because they appear to be producing oil.

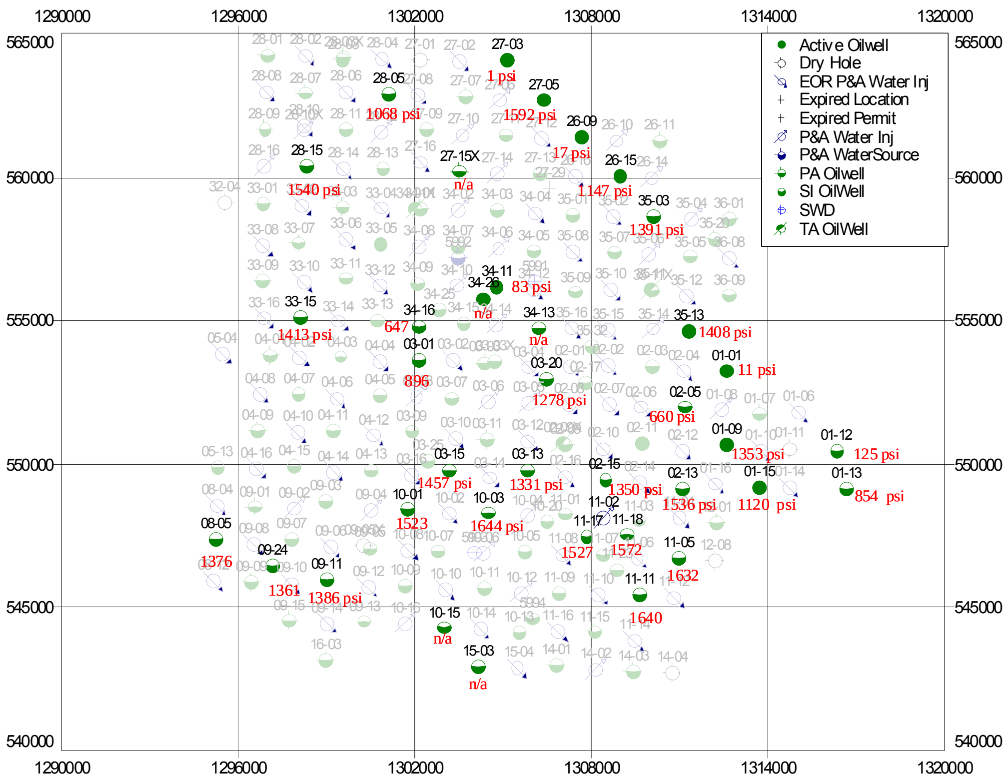


Figure 5.2: Wells with fluid level data (calculated bottomhole pressure indicated).

5.2 Operations and Pump Units

The field has the following beam pump units either active or available (on locations with shut-in wells):

Number of Units	*Size*	*Capacity at pumped off conditions*
23 units	160C	170 bbl/day
7 units	114C	142 bbl/day
4 units	57C	51 bbl/day
1 unit	54	+/- 50 bbl/day

Figure 5.3 gives a picture of the current TMCBSU Beam Pump inventory. The highest current production rate (42 bbl/day) is below the capacity of the smallest pump unit, suggesting that there are ample opportunities for optimizing pumping/lifting operations especially in wells with high dynamic fluid levels.

A preliminary productivity index attempt indicates that an incremental production of up to 79 bbl/day of incremental oil production may be achieved from existing and shut-in wells (See Table A5.2, Appendix). However, the incremental production estimates on the active wells have a high degree of uncertainty due to the quality of the following information:

1. The current well test method is based on a "5 gal bucket test", which is <u>not reliable</u> for monthly allocation or PI estimates,
2. The "Last 6 months Moving Averages" for both total fluid production and oil-cut were utilized, but again quality of allocations is important, and
3. There is little to no information on mechanical integrity and the condition of present equipment to support the estimates.

Incremental oil production in the TMCBSU is undoubtedly possible. Information to best reactivate and optimize production is still lacking. For example, fluid levels at hand are of tremendous value, but regular fluid levels (i.e. monthly) are better in assisting production up-time improvements. It is also highly recommended to improve well test capabilities for individual wells, both the quality and quantity One alternative is to utilize (lease or buy) a portable test unit, as shown in Figure A5.3 in the Appendix.

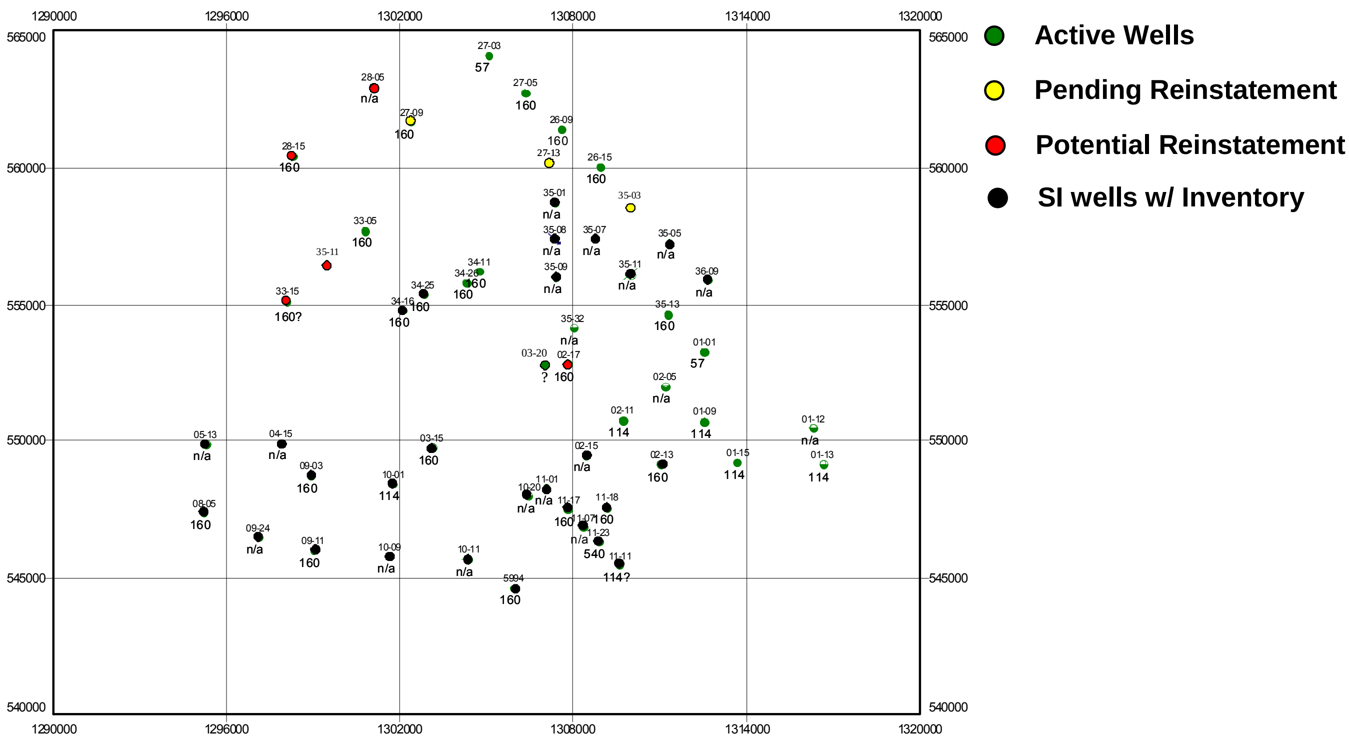


Figure 5.3: Beam Pump Inventory.

Another recommendation for optimizing pumping operations is to utilize a “skid mounted pump unit”, similar to the 160 unit currently on 33-13 well (see Figure A7.9, Appendix), for short term testing of wells planned for future re-activations. The gas motor and propane tank on the skid mounted unit allows for better speed adjustment (strokes per minute) than an electric motor and well tests and fluid levels can be used to correctly size pumps, rod string and motors. Capital commitments are minimized by using a unit that is already in inventory, and the “skid mount” set-up enables easier transportation from one location to another.

It became apparent during the field visit that the current Mean Time Between Failures (MTBF) is too low. Some wells are only running 3-4 months at a time, before they had to be shut down for mechanical problems. With a few operational adjustments and training for field personnel, it should be possible to improve the MTBF quite drastically. For example, ensure the pump units are properly leveled and aligned to remove unnecessary stresses from the rod strings, pumps and gear boxes, enabling longer run times. Knowing the dog-leg severity of the well, property utilization of rod guides, and potentially using polylined tubing may aid in the reduction of rod wear / tubing leaks. Lastly, utilizing echometers (to measure fluid levels), dynamometer (to monitor wells), and pump-off controllers to properly shut down pumped off wells will help optimizing operations. This is by no means the end of optimization but the beginning. Over time good practices will begin to show in increased MTBF of the TMCBSU wells.

One final comment on operations is in regards to well files, the importance of compiling and maintaining an up-to-date record for each well’s completion, workovers, fill, lost-in-hole equipment, etc. Provident has indicated that several wells may have up to several hundred feet of sand above the perforations, complicated by asphaltenes and/or paraffins problems. Proper clean-out and regular solvent or hot oil treatments will ease the downtime among the producers. Other problems mentioned were mechanical, such as parted tubing and casing leaks. However, missing information on present completion equipment and its condition, as well as recent well interventions, makes it hard to evaluate a well’s operation and plan appropriate workovers. It is recommended to source and catalogue as much historical information as possible in individual well files, then maintain an up-to-date well file moving forward.

5.3 TMCBSU Waterflood – A Few Comments

The premature water breakthrough and possibly water channeling during the initial waterflood stage appears to have been caused by the excessive surface injection pressure. According to the injection reports, initial injection pressures were consistently in the 2,000 – 2,400 psi range. A preliminary review of (Instantaneous Shut-in Pressure) ISIP of fractured wells indicated that 2,400 psi surface pressure plus a hydrostatic column of injection water exceeded the frac gradient of the formation. This is illustrated in Figure 5.4.

It is important to understand why high injection pressures were applied in the first place. It will help in evaluating similar issues during a potential redevelopment of the TMCBSU, such as a future waterflood re-activation. Possible causes for the high injection pressures could be factors such as the degree of formation heterogeneity (e.g. laminations, directional permeability), possible swelled in-situ clays due to injection water incompatibilities (core mineralogy reports for clay type and content), injection water quality (filtered/unfiltered) or possibly excessive oil carry over (plugging of formation). For a potential future waterflood reactivation, safe injection pressures can be deducted from historical or new “Step Rate Tests” for example as part of a future Pre-Frac treatment on a new well.

In conclusion, there are a lot of questions regarding the TMCBSU waterflood project that can only be answered by reviewing historical waterflood installation documentation. It is recommended to source and review any available information on the topic, before planning any re-activation projects.

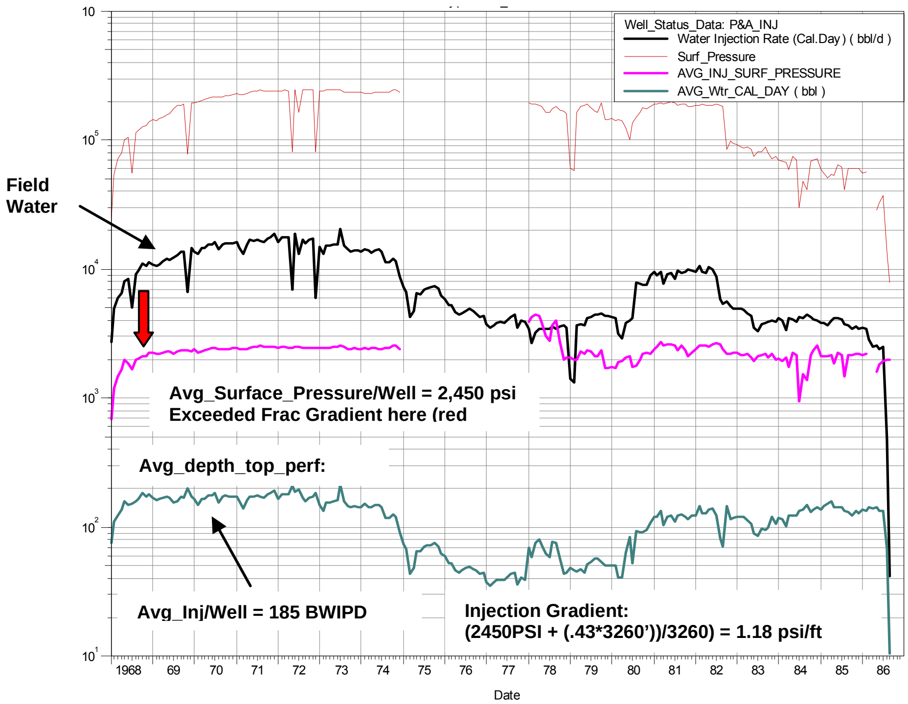


Figure 5.4: Injection pressures during the waterflood period (1968 – 1986).

5.4 Horizontal Wells In The Cut Bank – A Few Comments

Horizontal wells drilled in the Cut Bank formation have experienced relatively low production rates. For example, the CBAU Armstrong (2-14H) and the CBAU 1-14H wells, operated by Quicksilver Resources Inc., have a maximum oil rate of 43 bbl/day and 36 bbl/day, respectively. The Damson CBSU (11-05) and Damson CBSU (11-07) have produced at rates of 164 bbl/day and 30 bbl/day, respectively. It is believed that the explanation of the failure of the TMCBSU waterflood will probably lead to the explanation as to why these nearby horizontal wells did not have a better performance. However without further information (historical), any further comments at this point would be pure speculations.

However, before drilling a horizontal well in the TMCBSU, it is strongly recommended to perform geological and reservoir simulation studies in order to minimize both operational and financial risk associated with horizontal drilling projects. As much information as possible regarding the formation and the field (geology, reservoir, operations) should be sourced and studied before undertaking a horizontal drilling project.

6 CONCLUSIONS AND RECOMMENDATIONS

6.1 Production Analysis

Field production analysis leads to the following conclusions:

- Drastic increase in water production shortly after the initiation of the waterflood program indicates poor waterflood sweep efficiency and possibly channeling (i.e. water recirculation).
- The northern part of the field recovered significantly higher oil volumes compared to the southern part. In particular, the Northeast area has significant oil production (with relatively low water production), without receiving comparable volumes of water injection, indicating it could be the better part of the field.
- The southern part of the field seems to be less productive, possibly associated with lower reservoir quality.
- The Cut Bank formation appears to be stratigraphic and heterogeneous, with different production performance across the field (in particular from north to south). Furthermore, the unit isopach map of 1972 is not representative of the field production performance indicating that the petro-physical cutoffs (e.g. porosity, water saturation) utilized to allocate net vs. gross pay may need to be redone.

The best well potential candidates include 17 primary and 10 secondary wells, 6 of the primary candidates and 4 of the secondary candidates are currently active producers, which leaves 11 primary and 6 secondary wells as the best wells to consider for reactivation.

The candidate selection based on Best 12-months, Last 6-months average oil/water and Total fluid/foot of perforated interval represented well performance. Historical well production was compared to field averages (oil/water) to verify candidate selection.

Reactivation of primary candidates either in the Northeast part of near past reactive waterflood areas where there is no significant water production is recommended.

Other recommendations to consider:

- Review workover program done in the period 1991-1993 (Mont-Mill Operating Co.). This appeared to have been successful and may provide solutions for future workovers.
- Identify opportunities for recompletion (opening additional pay within the Cut Bank formation). Review logs and identify zones not perforated.
- Conduct a fracture analysis for a better understanding of the reservoir's response to fracture design. A preliminary review of 25 wells indicated an inverse trend with better results (higher production) from low volume (fluid and proppant) fracture treatments.
- Conduct a detailed waterflood evaluation to identify un-swept areas, and areas where the flood channeling is more (or less) severe.
- Consider digitizing logs for use in future studies. It may not be economical to digitize all TMCBSU logs, so consider targeting wells evenly spaced throughout the field. For a geological study (discussed below), all logs are required, but paper copies are sufficient.
- Conduct a geological (static) and reservoir simulation (dynamic) study for a better description of the formation and fluid movements within. Updated geological maps (e.g. structure map, isopach map) and a 3D model together with a reservoir simulation will complement and help explain the results of the production analysis.

6.2 Operations Review

The operations review lead to following conclusions:

- Based on recent fluid levels, the field seems to be pressured up (close to original reservoir pressure). However, some wells are not being properly “pumped off” (indicated by a straight line WOR on decline curves). On the other hand, low fluid levels in a few active wells indicate limited or partial communication with the reservoir, again a reason to review past stimulation treatments.

- Current well test capabilities are inadequate, as they do not allow for individual well tests. Enabling proper well tests is critical in managing operations.

- There is incremental production to be gained from existing active wells by optimizing lifting operations and improving equipment integrity issues. Premature failures are occurring which result in a low “Mean Time Between Failures” (MTBF). The MTBF can be improved.

- With regards to the waterflood project and the premature water breakthrough, it seems that high-surface injection pressure may have been responsible. It appears to have exceeded frac pressures, causing premature injection water channeling.

- Horizontal wells drilled in the Cut Bank formation have experienced relatively low production rates to date. This fact encourages a more thorough evaluation of the TMCBSU from a geological and petrophysical standpoint in addition to the production and operational analysis done here.

- During this review, it became apparent that a lot of critical field and well information is missing. It made this project challenging and in order to address future field development plans, some gaps in the data will have to be addressed.

Based on these conclusions, the main recommendations can be summarized as follows:

Short-to-Medium Term

- Optimize operations and production from existing wells
- Provide improved well tests capabilities (e.g. portable unit)
- Improve MTBF with operational adjustments and personnel training

Long Term

- Consider reactivating candidates selected based on the production analysis
- Build and maintain complete well files. Source and catalogue available information (BLM and DNRC offices in Great Falls and Billings, Montana).
- Conduct a geological (static) and reservoir simulation (dynamic) study prior to embarking on a drilling program (horizontal or infill) or a waterflood re-activation project to address reservoir and geological uncertainties.

In conclusion based on both reviews, a redefinition of the geological model is recommended as the next step. As mentioned earlier, the existing isopach map does not support the better well locations. It is believed a redefined geological model and updated geological maps will provide valuable insight for field development planning. Additionally, in order to properly evaluate drilling projects, it is recommended to include a reservoir simulation study to define the actual reservoir flow units. This is time-consuming and costly, but could be controlled by focusing on one of the better areas (e.g. northeast section), rather than whole unit. In any case, it is important to note that information available to date is insufficient for recommending a long-term field development plan. We strongly recommend sourcing available data and conducting follow-up studies prior to initiating a drilling program or a new waterflood project.

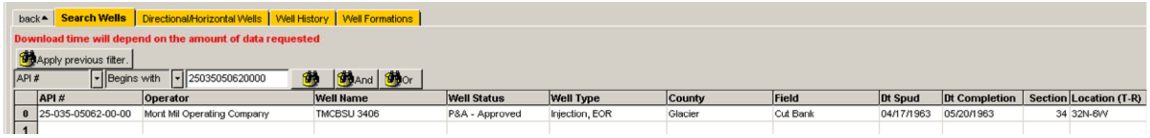
7 APPENDIX

7.1 Appendix to Data Overview (Chapter 2)

7.1.1 Well inventory and well names – assumptions

1. Well 34-06 (API: 25035050620000)

IHS injection well with well name: “2D” corresponds with DNRC injection well “34-06”. Assume it is a duplicate. Keep the IHS record (do not add fro DNRC), but rename the well from “2D” to “34-06”.
(Same API: 25035050620000).



DNRC Online Database

2. Well 27-03 (API: 25035211000000) & IHS lease record

IHS “Lease” record is assigned to the same API as DNRC well “27-03”.

IHS Well Name: “LEASE”
IHS Production ID: 125001051880
API: 25035211000000

Add both records (“27-03” record from DNRC and “LEASE” record from IHS) for completeness. The “LEASE” record includes information otherwise missing from the “per-well” data in the years 1979-83.

3. Wells: 22-14, 28-03X and 28-10X

The wells 22-14, 28-03X and 28-10X are all indicated on the isopach map, but they are not included in the IHS or DNRC database with that well name. XY locations of the (DNRC) wells listed below, suggest they may be the missing wells (APIs not found in IHS). The wells will be added to the database with the assumed well name.

DNRC Well Name	Assumed	Type	API
RIECKHOFF 1	22-14	Dry Hole	25035052020000
Blackfeet TR 4	28-03X	PRD	25035051770000
TRIBAL-1094 1	28-10X	PRD	25035051290000

4. Additions to the project database based on XY locations

The following wells, downloaded from the DNRC online database, have been added to the project database, based on XY locations only. Their names, as recorded in the DNRC database do not match the well names on the isopach map, but their XY locations put them within the TMCBSU boundary.

API #	Operator	Well Name_DNRC	Well Name Convention (OFM)	Well Status	Well Type	County	Field
25073055520000	Mont Mil Operating Company	**TRIBAL A-3**	**02-09**	P&A - Approved	Oil	Pondera	Cut Bank
25073055530000	Mont Mil Operating Company	**TRIBAL 2-3**	**03-11**	P&A - Approved	Oil	Pondera	Cut Bank
25073210690000	Taylor, John F. Etal	**Yellowowl Allottee 8-6**	**08-06**	Expired Permit	Oil	Pondera	Cut Bank
25073060090000	Mont Mil Operating Company	**H.JOHNSON 1291**	**12-01**	P&A - Approved	Dry Hole	Pondera	Cut Bank
25035217840000	Mont Mil Operating Company	**27-29 TRIBAL**	**27-29**	Expired Permit	Expired Loca	Glacier	Cut Bank

All records belong to the TMCBSU, based on XY locations.

- Add to database as follows:

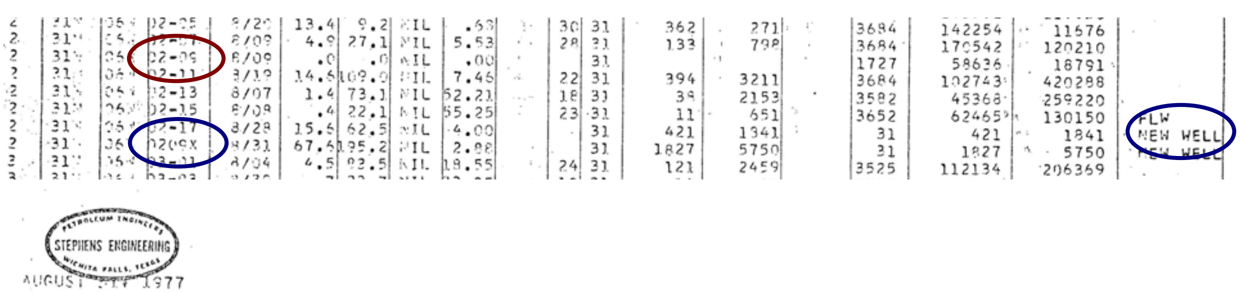
"TRIBAL A-3"	add as 02-09 (on isopach map)
"TRIBAL 2-3"	add as 03-11 (on isopach map)
"Yellowowl Allotte 08-06"	add as 08-06 (not on isopach map)
"H. JOHNSON 1291"	add as 12-01 (on isopach map)

5. Well 02-09 vs. 02-09X (DNRC records)

<u>02-09 (API: 25073055520000)</u>
Renamed from "Tribal A-3" (see previous slide).
"Early period" well with production data from 1968 – '73. Noted as PA in Sept. 1977.

<u>02-09X (API: 25073212200000)</u>
Listed as "New Well" in August 1977 reports (not on the list prior month - July '77).
Production data from 1977-'78 (a "later period" well).

Both records added to the database. Assume two separate wellbores.*



02-05	9/20	13.4	9.2	OIL	.63	30	31	362	271	3684	142254	11676
02-07	8/09	4.9	27.1	OIL	5.53	28	31	133	798	3684	170542	120210
02-09	8/09	.0	.0	OIL	.00		31			1727	58636	18791
02-11	3/19	14.6	109.0	OIL	7.46	22	31	394	3211	3684	102743	420288
02-13	8/07	1.4	73.1	OIL	52.21	18	31	39	2153	3582	45368	259220
02-15	8/09	.4	22.1	OIL	55.25	23	31	11	651	3652	62465	130150
02-17	8/28	15.5	62.5	OIL	4.00		31	421	1341	31	421	1841 FLW NEW WELL
0209X	8/31	67.6	135.2	OIL	2.88		31	1827	5750	31	1827	5750 NEW WELL
03-01	8/04	4.5	93.5	OIL	18.55	24	31	121	2459	3525	112134	206369

PETROLEUM ENGINEERS
STEPHENS ENGINEERING
WICHITA FALLS, TEXAS
AUGUST 1977

*Sample of available data.

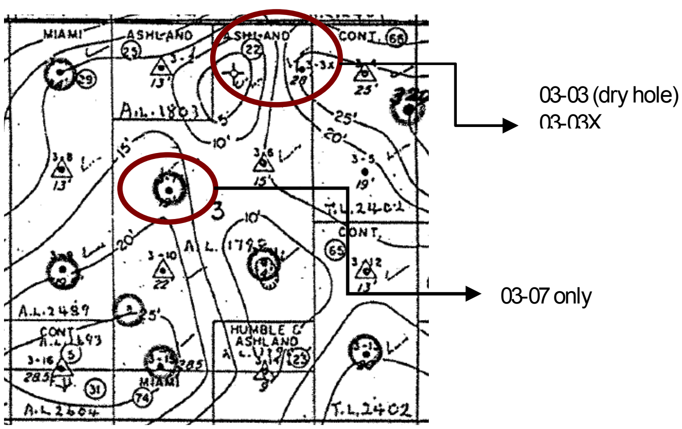
6. Wells 03-03 vs. 03-03X and 03-07 vs. 03-07X

03-03 (303):
API and location indicate that IHS well: 03-03 (303) is the same as DNRC well 03-03X. Assume the records are duplicates. Keep the IHS record, but re-name the well “03-03X”. It is a “later period” well, with production from the ’80s and ’90s.

Add the DNRC well “03-03” (no “X”); XY location fits.
“Early period” well with production from 1968 – ’78.

03-07 (307):
API and location indicate that IHS well 03-07 (307) is the one shown on the isopach map. Production from 1968-’78. Consider DNRC well 03-07X a duplicate. Do not add.

	Production ID	API	Well Name
IHS:	125001114480	25073210330000	03-03 (303) – rename to 03-03X
DNRC:	N/A	25073210330000	03-03X – duplicate, do not add
DNRC:	N/A	25073055640000	03-03 – on map, ok (add)
IHS:	125001114481	25073210320000	03-07 (307) – on map, ok
DNRC:	N/A	25073210320000	03-07X – not on map (duplicate?)



7. Well 27-08X vs. 27-08

Well 27-08X is listed on injection reports for 1984, but without any actual injection recorded. Original scans shows a cumulative injection of 161,786 bbl which is the same figure recorded for 27-08.

⇒ No 27-08X well included in IHS or in the electronic DNRC database.
⇒ Rename 27-08X to 27-08. Assume same well.

March '84. Well 27-08 listed with a cum of 161,786 bbls

2706	ITS				W		232511
2708	ITS				W		161786
2710	ITS				W		336039
2712	IWA	31	24	2000	W	7	257450

April '84. Well 27-08X listed with a cum of 161,786 bbl (same as 27-08 the month before)

31	84/04	TMCBSU/NB	2616	27	32N	6W	372,547	TA
32	84/04	TMCBSU/NB	2702	27	32N	6W	156,497	TA
33	84/04	TMCBSU/NB	2706	27	32N	6W	232,511	TA
34	84/04	TMCBSU/NB	2708X	27	32N	6W	161,786	TA
35	84/04	TMCBSU/NB	2710	27	32N	6W	336,039	TA

8. Well 27-12X vs. 27-12

⇒ No 27-12X well included in IHS or in the electronic DNRC database.
⇒ Rename 27-12X to 27-12. Assume same well.

Date	Well	INJ	Cum
Jan '80	27-12X	N/A	230,841
Jan '80	27-12	375	375
Feb '80	27-12X	N/A	230,841
Feb '80	27-12	375	750
March '80	27-12	13	231,604

Only well 27-12 listed in March '80.
The cum add up for both 27-12X and 27-12 (230,841 + 750 + 13 = 231,604).

This confirms the two wells are considered the same.

March 1984 - no 27-12X listed. Only 27-12 (with a cum of 257,450 bbls)

2708	ITS				W		161786
2710	ITS				W		336039
2712	IWA	31	24	2000	W	7	257450
2714	ITS				W		26315
2716	ITS				W		232015
2802	IPS				W		263043

April 1984 - well 27-12 renamed 27-12X? Same Cumulative figure (add 2 for that month)

33	84/04	TMCBSU/NB	2706	27	32N	6W		232,511	TA
34	84/04	TMCBSU/NB	2708X	27	32N	6W		161,786	TA
35	84/04	TMCBSU/NB	2710	27	32N	6W		336,039	TA
11	84/04	TMCBSU/NB	2712X	27	32N	6W	2	257,452	1,500
36	84/04	TMCBSU/NB	2714	27	32N	6W		26,315	TA
37	84/04	TMCBSU/NB	2716	27	32N	6W		232,015	TA

9. 28-10 vs. 28-10X (DNRC records)

28-10 (API: 25035210530000): Injection data from 1969 – '74 & 1979 – '82

28-10X (API: 25035051290000): Renamed from "Tribal - 1094" (see item 3)

Assume two separate wellbores and add both records to the project database. However, all injection data has been linked to 28-10. 28-10X was only listed with one injection value, which also equals its cumulative injection (Dec. '79). Based on the other "X" wells, the later period injection is assumed to belong to this one, but the original scans recorded them under 28-10, and we will leave them as such.

28	32N	06W	[illegible]	2000	693	31	22.4	451822
28	32N	06W	28-08				.0	253998
28	32N	06W	28-10				.0	236281
28	32N	06W	28-12	1561	2034	31	65.6	605663
28	32N	06W	28-14	1455	2758	31	89.0	729938
28	32N	06W	28-16	1616	1484	31	47.9	255106
28	32N	06W	2810X	1819	536	31	17.3	536
33	32N	06W	[illegible]				.0	596094

10. 34-01 vs. 34-01X

34-01 vs. 34-01X: IHS record named 34-01 has the same API as the DNRC record 34-01X (API: 25035214010000). Assume the two records identify the same wellbore, and rename the IHS record to 34-01X (do not add the DNRC record). The "X" wells seem to be the "later period" wells. This one has production data from the '80s.

Add DNRC record 34-01 (API: 25035050860000) – without the "X". This one has production data from 1968 – '78. It fits with the theory that the wells without the "X" are the "early period" wells.

11. Disposal Wells 5991 and 5993: Madison Formation

The injection report below confirms that the two TMCBSU disposal wells (5991 & 5993) were completed for injection into the Madison formation.

(SUBMIT IN DUPLICATE)
ARM 36.22.307
ARM 36.22.1234

TO
Board of Oil and Gas Conservation
of the State of Montana
2535 St. Johns Ave.
BILLINGS, MT 59102

REPORT OF SUBSURFACE INJECTIONS

For Month of Jan 19 90

Field SW Cutbank County Glacier & Pondera Operator Mont-Mill Operating Co., Inc.

Unit or Lease Name Two Medicine Cut Bank Sand Unit Formation Injected Into Madison

Injection Fluid (water, gas, air, LPG, etc.) water

Source of Injection Fluid produced water

Type of Project (Secondary Recovery, Pressure Maint., Disposal) Disposal

INJECTION DATA

INJECTION WELL INFORMATION							
Name	No.	Sec.	Twp.	Rge.	Monthly Inj. bbls, MCF, gals	Cummulative Inj. bbls, MCF, gals	Avg. Surface Inj. Pressure
5991	N	34	32N	6W	15,635	843,198	
5993	S	10	31N	6W	26,366	1,184,027	

7.2 TMCBSU Field Overview (Chapter 3)

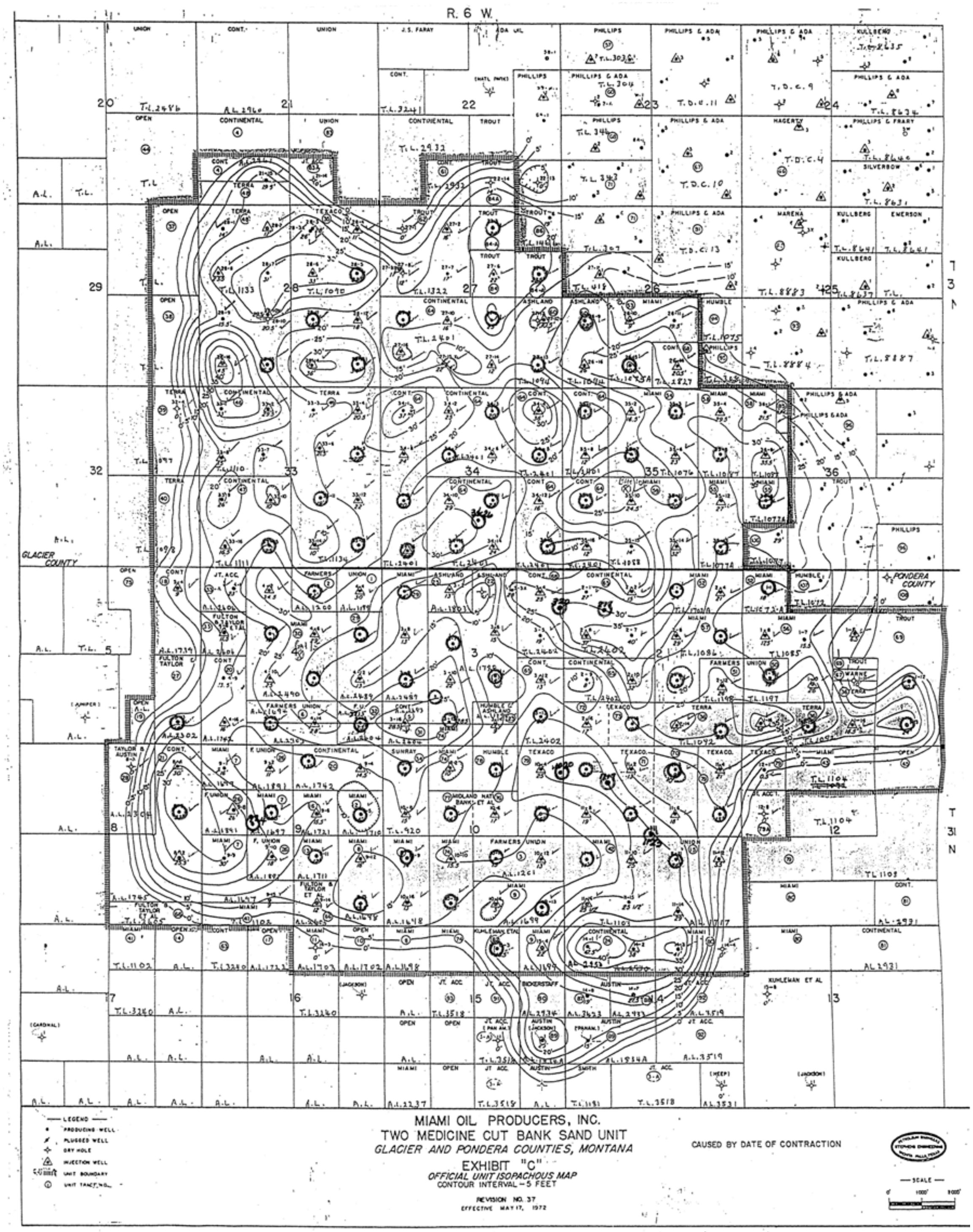


Figure A 7.1: TMCBSU Isopach Map (1972)

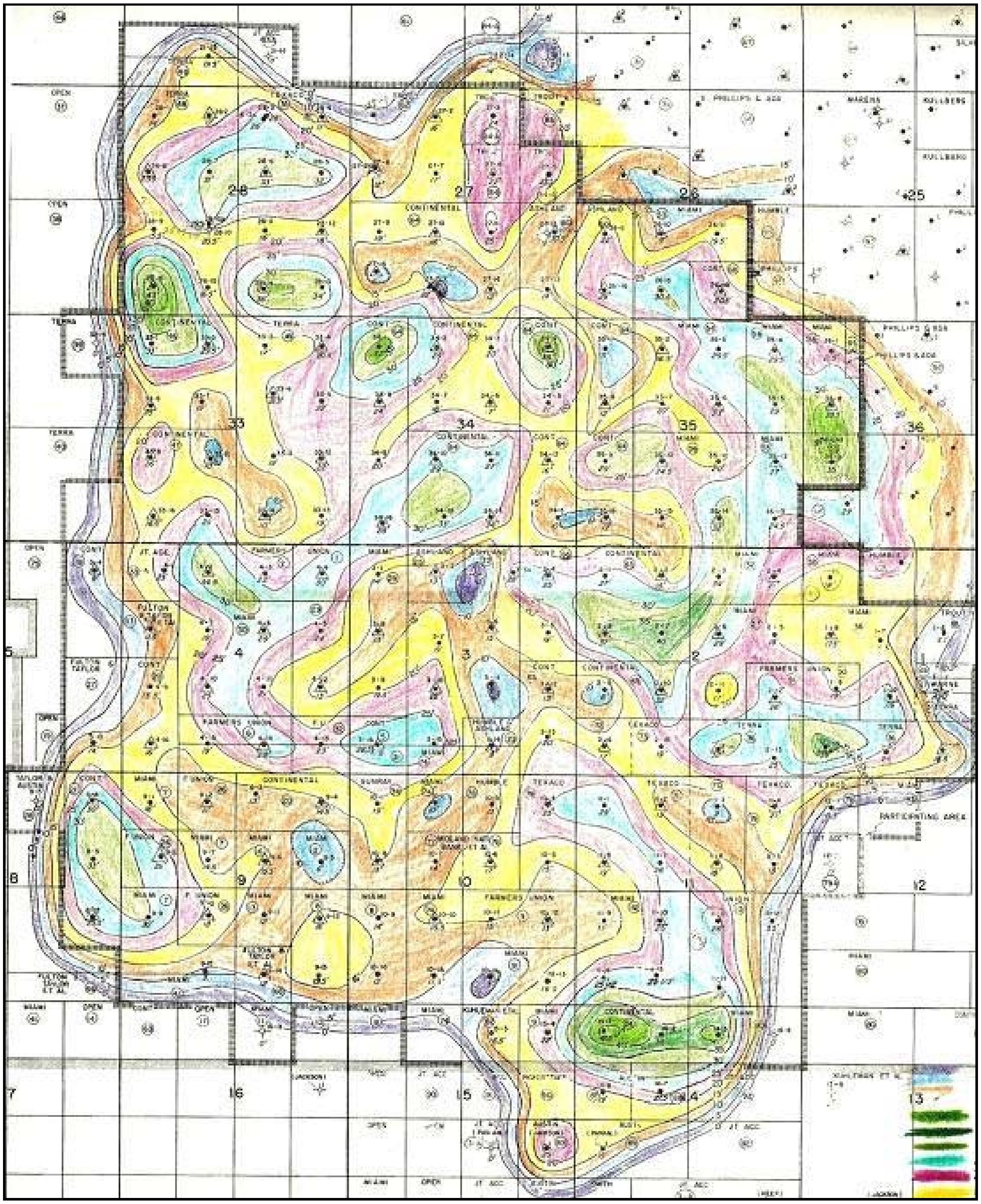


Figure A 7.2: TMCBSU Isopach Map – colored for visual representation of pay thickness.

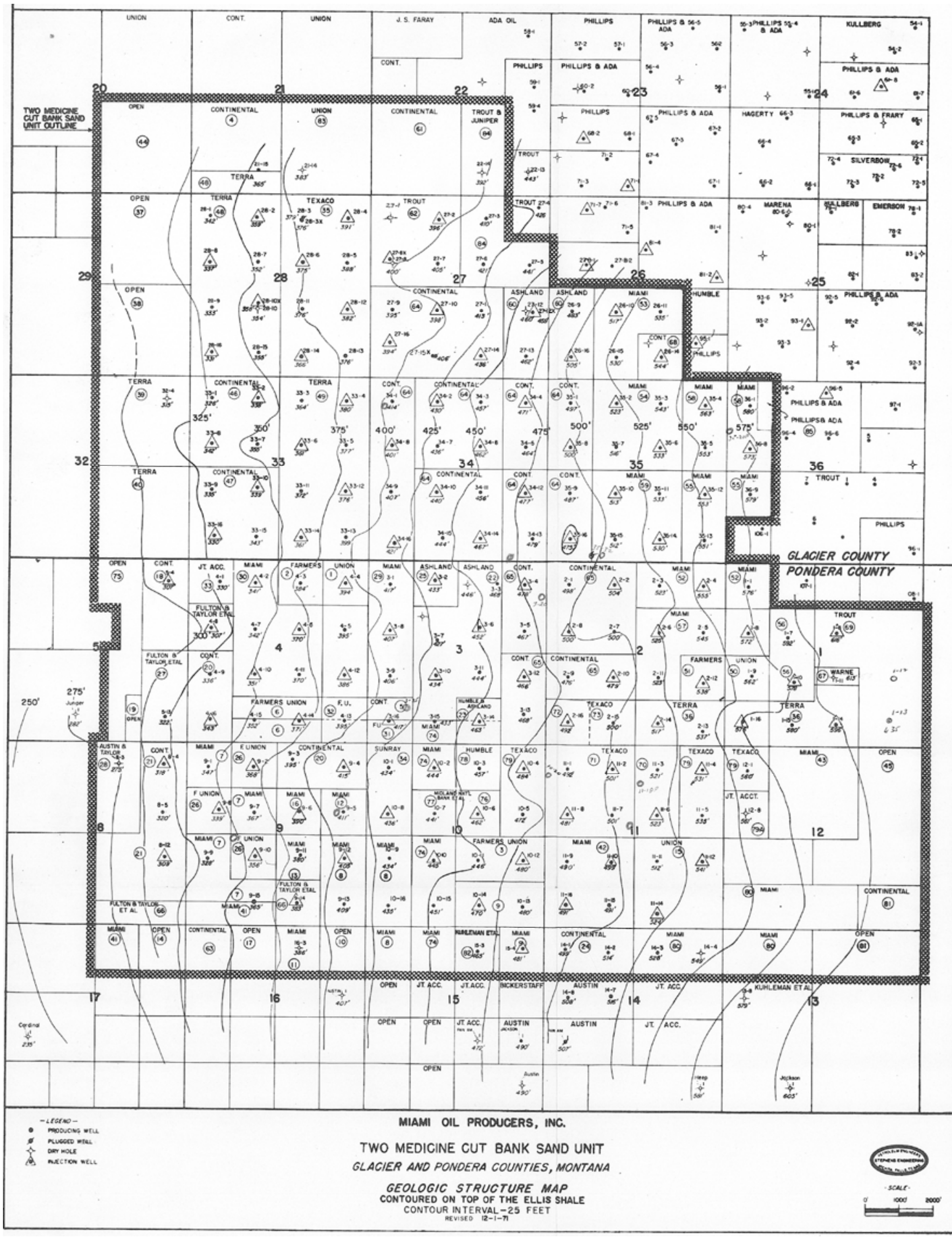


Figure A 7.3: TMCBSU Structure Map.

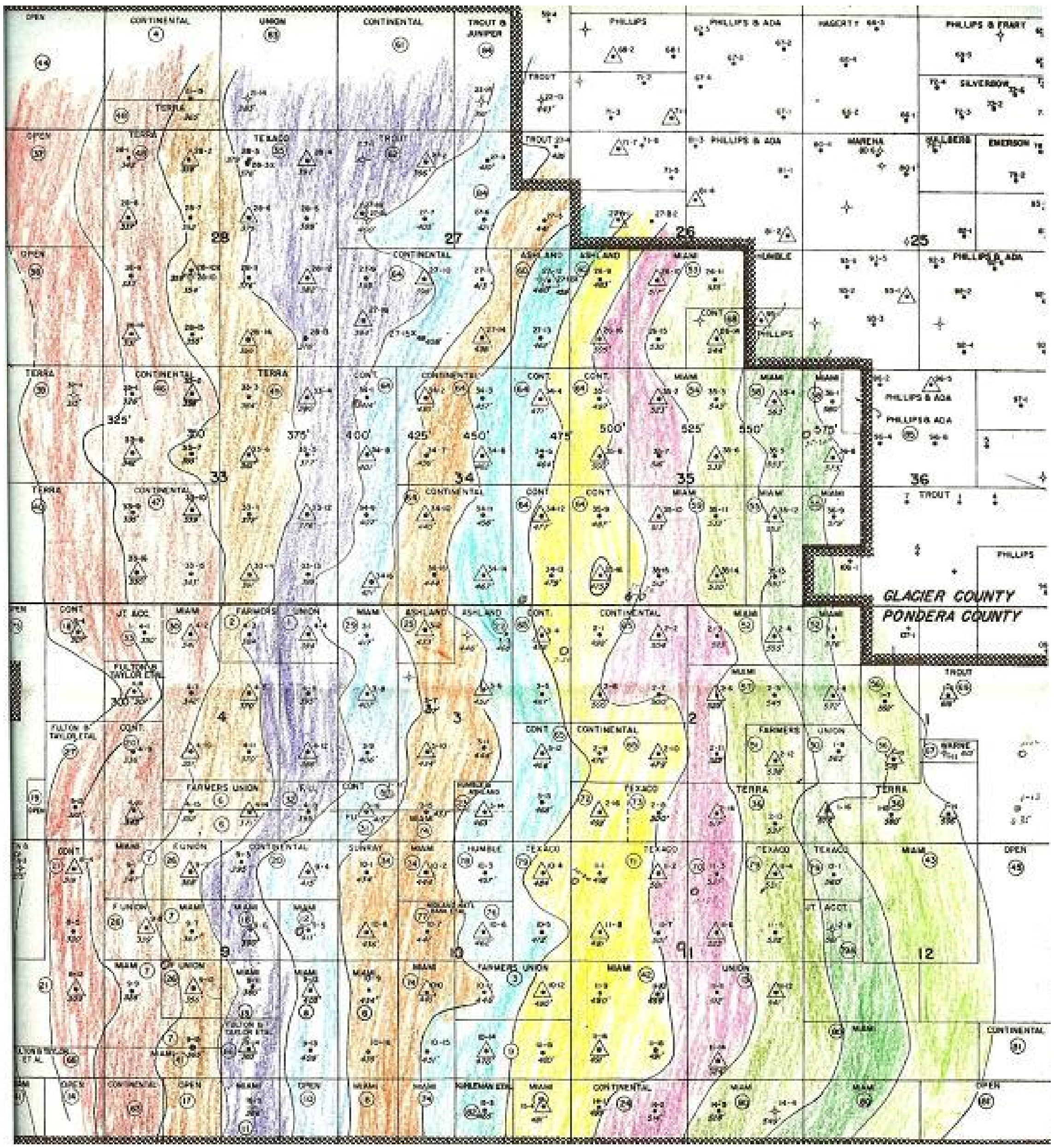


Figure A 7.4: TMCBSU Structure Map – colored for visual representation of "updip" section.

Table A 7.1: TMCBSU Inventory List

WELL NAME	API	SOURCE	FORMATION	OPERATOR	WELL STATUS
01-01	25073056240000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
01-09	25073055510000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
01-15	25073210610000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
02-11	25073055480000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
26-09	25035210660000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
26-15	25035071970000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
27-03	25035211000000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
27-05	25035211010000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
33-05	25035050640000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
34-11	25035050490000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
34-26	25035217830000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
35-13	25035071800000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	Active_PRD
5991	25035210140000	IHS	MADISON	PROVIDENT ENERGY ASSOCIATION LLC	Active_DISP
01-12	25073211110000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
01-13	25073211080000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
02-03	25073055670000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
02-05	25073055550000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
02-13	25073055400000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
02-15	25073055430000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
02-17	25073212190000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
03-01	25073056310000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
03-03X	25073210330000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
03-07	25073210320000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
03-09	25073056330000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
03-13	25073055460000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
03-15	25073210190000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
03-20	25073212870000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
03-25	25073212820000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
04-03	25073055690000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
04-05	25073056370000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
04-07	25073056350000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
04-11	25073056270000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
04-13	25073055300000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
04-15	25073055370000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
05-13	25073210750000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
08-05	25073055250000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
09-03	25073210150000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
09-05	25073210210000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
09-07	25073210220000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
09-11	25073210420000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
09-13	25073210630000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
09-24	25073212800000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
10-01	25073055310000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
10-03	25073055330000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
10-05	25073055210000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
10-07	25073055170000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
10-09	25073210440000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
10-13	25073210950000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
10-15	25073210920000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
10-20	25073212860000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
11-01	25073055340000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
11-03	25073055280000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
11-05	25073055160000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
11-07	25073055200000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
11-09	25073210230000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
11-11	25073055140000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
11-17	25073212180000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
11-18	25073212880000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
11-23	25073212850000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
15-03	25073210800000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
27-09	25035051350000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
27-11	25035051340000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
27-13	25035072290000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
28-05	25035072780000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
28-11	25035051310000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
28-13	25035210480000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
28-15	25035210750000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
33-11	25035210570000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
33-13	25035050310000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
33-15	25035050250000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
34-03	25035050850000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
34-05	25035072790000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
34-07	25035050650000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
34-09	25035050420000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
34-13	25035050210000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
34-15	25035050300000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
34-16	25035050230000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
34-25	25035217850000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
35-01	25035050820000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD

WELL NAME	API	SOURCE	FORMATION	OPERATOR	WELL STATUS
35-03	25035072550000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
35-05	25035072030000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
35-07	25035071880000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
35-09	25035050360000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
35-11X	25035213520000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	SI_PRD
35-32	25035214050000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
36-09	25035071890000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
5994	25073210600000	IHS	MADISON	PROVIDENT ENERGY ASSOCIATION LLC	SI_PRD
02-09X	25073212200000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	TA_PRD
34-01X	25035214010000	IHS	CUT BANK LOWER	PROVIDENT ENERGY ASSOCIATION LLC	TA_PRD
35-11	25035071780000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	TA_PRD
01-07	25073210520000	IHS	CUT BANK LOWER	MONT-MILL OPER COMPANY INCORPORATED	P&A_PRD
02-09	25073055520000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
03-03	25073055640000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
03-11	25073055530000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
04-01	25073210940000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
04-09	25073210360000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
09-01	25073210200000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
09-09	25073210380000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
09-15	25073210640000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
10-11	25073055110000	IHS	CUT BANK LOWER	MONT-MILL OPER COMPANY INCORPORATED	P&A_PRD
11-15	25073210890000	DNRC	CUT BANK	Miami Oil Producers, Inc.	P&A_PRD
12-01	25073060090000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
14-01	25073210780000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
14-03	25073210540000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
16-03	25073210620000	DNRC	CUT BANK	Miami Oil Producers, Inc.	P&A_PRD
21-15	25035210830000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
26-11	25035072120000	IHS	CUT BANK LOWER	MONT-MILL OPER COMPANY INCORPORATED	P&A_PRD
27-07	25035051550000	IHS	CUT BANK	PROVIDENT ENERGY ASSOCIATION LLC	P&A_PRD
27-15X	25035210180000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
28-01	25035210820000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
28-03	25035210410000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
28-03X	25035051770000	DNRC	CUT BANK	Texaco Exploration and Production Inc.	P&A_PRD
28-07	25035051560000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
28-09	25035210810000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
33-01	25035210710000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
33-03	25035071490000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
33-07	25035210700000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
33-09	25035210730000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
34-01	25035050860000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_PRD
35-20	25035214020000	IHS	CUT BANK	MONT-MILL OPER COMPANY INCORPORATED	P&A_PRD
36-01	25035072010000	IHS	CUT BANK	MONT-MILL OPER COMPANY INCORPORATED	P&A_PRD
01-06	25073210730000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
01-08	25073056400000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
01-10	25073210720000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
01-14	25073210830000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
01-16	25073210480000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-01	25073055650000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-02	25073055710000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-04	25073056420000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-06	25073055580000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-07	25073055560000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-08	25073055570000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-10	25073055470000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-12	25073060070000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-14	25073210340000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
02-16	25073055450000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-02	25073210300000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-04	25073055630000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-05	25073055590000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-06	25073055600000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-08	25073056320000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-10	25073210290000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-12	25073055490000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-14	25073055420000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
03-16	25073210400000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
04-02	25073056340000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
04-04	25073055700000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
04-06	25073056260000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
04-08	25073210740000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
04-10	25073056250000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
04-12	25073056360000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
04-14	25073055320000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
04-16	25073210390000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
05-04	25073210790000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
08-04	25073210370000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
08-12	25073210550000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
09-02	25073055360000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
09-04	25073210140000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ

Provident Energy Associates of Montana, LLC

Schlumberger

WELL NAME	API	SOURCE	FORMATION	OPERATOR	WELL STATUS
09-06	25073210410000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
09-08	25073055240000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
09-10	25073055130000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
09-12	25073210430000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
09-14	25073210810000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
10-02	25073210350000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
10-04	25073055350000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
10-06	25073055220000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
10-08	25073055230000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
10-10	25073210450000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
10-12	25073055120000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
10-14	25073210530000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
10-16	25073210930000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
11-02	25073055290000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
11-04	25073060080000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
11-06	25073055180000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
11-08	25073055190000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
11-10	25073210460000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
11-12	25073210990000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
11-14	25073210840000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
11-16	25073210900000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
14-02	25073210760000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
15-04	25073210910000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
26-10	25035072240000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
26-14	25035210170000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
26-16	25035210440000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
27-02	25035211040000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
27-06	25035072870000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
27-08	25035210990000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
27-10	25035051320000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
27-12	25035210770000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
27-14	25035051070000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
27-16	25035051170000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
28-02	25035210540000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
28-04	25035051760000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
28-06	25035051580000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
28-08	25035210550000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
28-10	25035210530000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
28-10X	25035051290000	DNRC	CUT BANK	McShane, C.R.	P&A_INJ
28-12	25035051300000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
28-14	25035210420000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
28-16	25035210800000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
33-02	25035210680000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
33-04	25035071350000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
33-06	25035210560000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
33-08	25035210720000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
33-10	25035210460000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
33-12	25035050410000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
33-14	25035050280000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
33-16	25035210450000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
34-02	25035050830000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
34-04	25035050840000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
34-06	25035050620000	IHS	CUT BANK LOWER	MONT-MILL OPER COMPANY INCORPORATED	P&A_INJ
34-08	25035050630000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
34-10	25035050470000	IHS	CUT BANK LOWER	MONT-MILL OPER COMPANY INCORPORATED	P&A_INJ
34-12	25035050370000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
34-14	25035050270000	IHS	CUT BANK LOWER	MONT-MILL OPER COMPANY INCORPORATED	P&A_INJ
35-02	25035072540000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
35-04	25035071980000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
35-06	25035071950000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
35-08	25035072880000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
35-10	25035071770000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
35-12	25035071790000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
35-14	25035071510000	IHS	CUT BANK LOWER	MONT-MILL OPER COMPANY INCORPORATED	P&A_INJ
35-15	25035072910000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
35-16	25035050240000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
36-08	25035072020000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_INJ
5992	25035210150000	DNRC	CUT BANK	Mont Mil Operating Company	P&A_WS
01-11	25073210970000	DNRC	CUT BANK	Miami Oil Producers, Inc.	P&A_DRY
08-03	25073210700000	DNRC	CUT BANK	Taylor, John F. Etal	P&A_DRY
09-05X	25073212810000	DNRC	CUT BANK	Provident Energy Assoc. Of Mt Llc	P&A_DRY
12-08	25073210870000	DNRC	CUT BANK	Miami Oil Producers, Inc.	P&A_DRY
14-04	25073211010000	DNRC	CUT BANK	Miami Oil Producers, Inc.	P&A_DRY
21-14	25035211120000	DNRC	CUT BANK	Miami Oil Producers, Inc.	P&A_DRY
22-14	25035052020000	DNRC	CUT BANK	Juniper Petroleum Corp.	P&A_DRY
27-01	25035211030000	DNRC	CUT BANK	Miami Oil Producers, Inc.	P&A_DRY
32-04	25035210860000	DNRC	CUT BANK	Miami Oil Producers, Inc.	P&A_DRY
5993	25073210120000	IHS	MADISON	PROVIDENT ENERGY ASSOCIATION LLC	P&A_DISP
08-06	25073210690000	DNRC	CUT BANK	Taylor, John F. Etal	EXPIRED
27-29	25035217840000	DNRC	CUT BANK	Mont Mil Operating Company	EXPIRED

7.3 Production Analysis (Chapter 4)

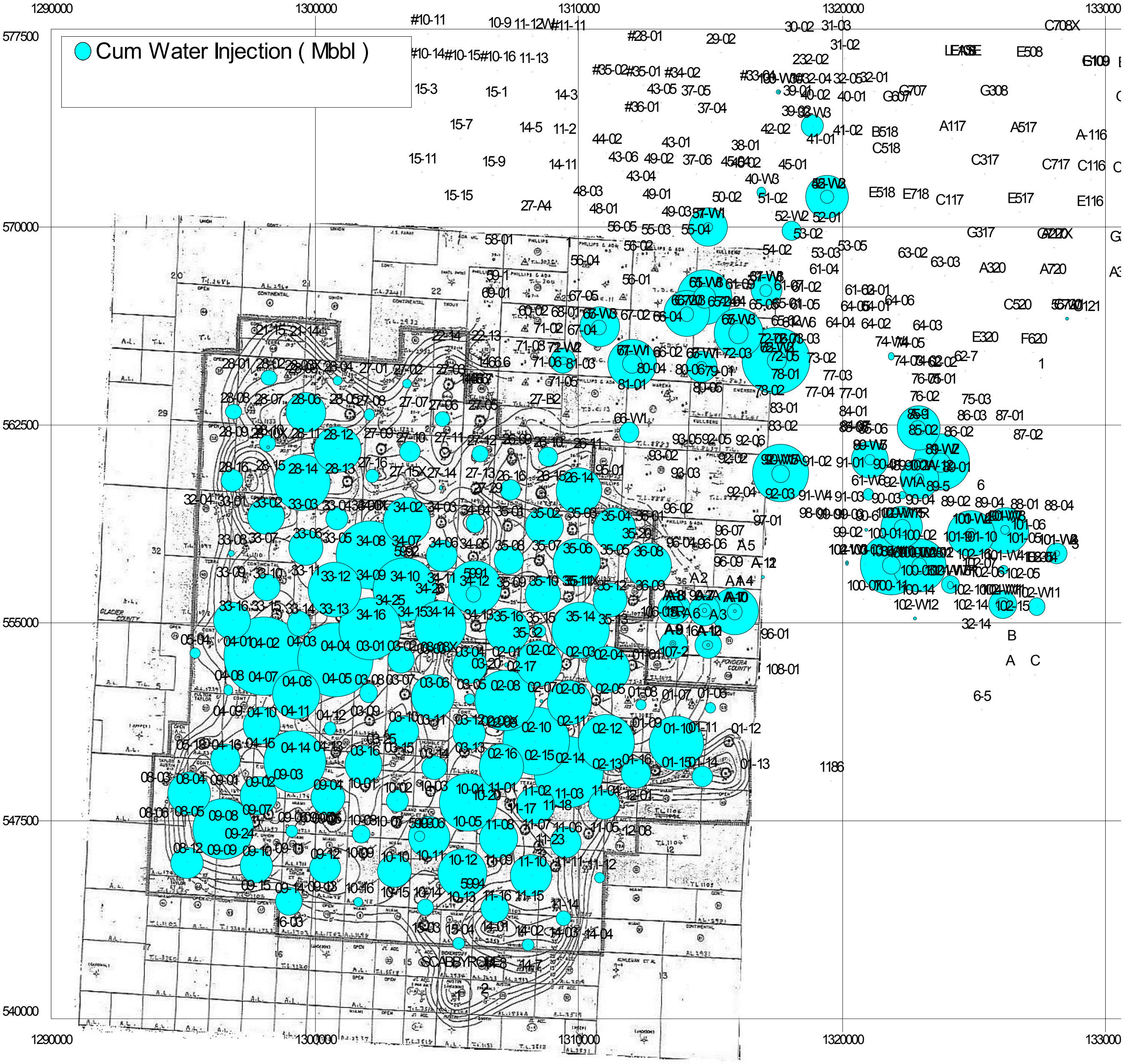


Figure A 7.5: Bubblemap of Cumulative Water Injection for TMCBSU and offset wells.

Table A 7.2: List of candidates considered with "Best 12 Months Average" criterion.

API	Well Name	Date	Best 12 Months (bbl/m)	Well Status
25073056240000	01-01	9/1/2008	1011	Active_PRD
25073055510000	01-09	9/1/2008	3099	Active_PRD
25073055670000	02-03	2/1/1986	6722	SI_PRD
25073055550000	02-05	6/1/1993	2084	SI_PRD
25073055480000	02-11	9/1/2008	2423	Active_PRD
25073055400000	02-13	1/1/2008	1264	SI_PRD
25073055430000	02-15	2/1/1986	1777	SI_PRD
25073056310000	03-01	3/1/1993	3096	SI_PRD
25073210320000	03-07	3/1/1984	2011	SI_PRD
25073056330000	03-09	2/1/1986	4417	SI_PRD
25073055460000	03-13	9/1/1984	2508	SI_PRD
25073210190000	03-15	9/1/1994	7499	SI_PRD
25073055690000	04-03	8/1/1994	3291	SI_PRD
25073055300000	04-13	2/1/1994	2757	SI_PRD
25073055370000	04-15	2/1/1986	2066	SI_PRD
25073055250000	08-05	4/1/2002	1109	SI_PRD
25073210150000	09-03	4/1/2002	3538	SI_PRD
25073210220000	09-07	1/1/1985	4140	SI_PRD
25073055330000	10-03	3/1/1994	2583	SI_PRD
25073055210000	10-05	12/1/1995	2682	SI_PRD
25073055170000	10-07	2/1/1994	1147	SI_PRD
25073210950000	10-13	10/1/1978	1178	SI_PRD
25073055340000	11-01	12/1/1986	2278	SI_PRD
25073212180000	11-17	10/1/2002	1621	SI_PRD
25035210660000	26-09	9/1/2008	1813	Active_PRD
25035071970000	26-15	9/1/2008	1799	Active_PRD
25035211000000	27-03	9/1/2008	1338	Active_PRD
25035211010000	27-05	9/1/2008	1947	Active_PRD
25035051350000	27-09	7/1/1994	3161	SI_PRD
25035051340000	27-11	6/1/1991	2082	SI_PRD
25035072290000	27-13	4/1/1994	2606	SI_PRD
25035072780000	28-05	7/1/1998	3214	SI_PRD
25035051310000	28-11	11/1/1991	1835	SI_PRD
25035210480000	28-13	2/1/1986	3336	SI_PRD
25035210750000	28-15	8/1/1994	1545	SI_PRD
25035050640000	33-05	9/1/2008	4474	Active_PRD
25035210570000	33-11	10/1/2003	2007	SI_PRD
25035050310000	33-13	2/1/1986	4689	SI_PRD
25035050850000	34-03	11/1/1993	5548	SI_PRD
25035072790000	34-05	10/1/1978	1683	SI_PRD
25035050420000	34-09	11/1/1988	1894	SI_PRD
25035050300000	34-15	10/1/1992	3349	SI_PRD
25035072550000	35-03	2/1/1986	2443	SI_PRD
25035072030000	35-05	10/1/1978	2643	SI_PRD
25035071880000	35-07	4/1/1994	2739	SI_PRD
25035050360000	35-09	11/1/1986	3402	SI_PRD
25035071800000	35-13	9/1/2008	1862	Active_PRD
25035071890000	36-09	6/1/1993	1660	SI_PRD

Table A 7.3: **List of candidates considered with "Last 6 Month Average" criterion**

API	Well Name	Date	MvAvg_Oil (bbl/m)	MvAvg_Water (bbl/m)	Class_Mavg	Well Status
25073212200000	02-09X	10/1/1978	763.00	4702.67	HOHW	SI_PRD
25073210210000	09-05	10/1/1978	323.33	731.5	HOHW	SI_PRD
25073210950000	10-13	10/1/1978	287.67	5460.5	HOHW	SI_PRD
25035213520000	35-11X	10/1/1978	213.17	2750.67	HOHW	SI_PRD
25035072790000	34-05	10/1/1978	205.83	834.67	HOHW	SI_PRD
25035210660000	26-09	9/1/2008	174.00	545	HOLW	Active_PRD
25073056350000	04-07	10/1/1978	136.83	1312.67	HOHW	SI_PRD
25073055140000	11-11	8/1/1994	133.00	125	HOLW	SI_PRD
25035050230000	34-16	12/1/2008	114.00	475.17	HOLW	SI_PRD
25073212870000	03-20	2/1/2007	105.83	367.67	HOLW	SI_PRD
25073055160000	11-05	9/1/1994	104.33	101.67	HOLW	SI_PRD
25073055250000	08-05	4/1/2002	99.50	920.5	HOHW	SI_PRD
25035210750000	28-15	8/1/1994	90.17	697	HOHW	SI_PRD
25073212880000	11-18	8/1/1994	89.33	604.67	HOLW	SI_PRD
25073212190000	02-17	7/1/1998	88.00	1151.5	HOHW	SI_PRD
25073055510000	01-09	9/1/2008	87.00	436.67	HOLW	Active_PRD
25035217830000	34-26	9/1/2008	86.83	215.83	HOLW	Active_PRD
25073210190000	03-15	9/1/1994	80.83	1550.5	HOHW	SI_PRD
25035051350000	27-09	7/1/1994	79.67	445.67	HOLW	SI_PRD
25073210150000	09-03	4/1/2002	79.00	689.5	HOHW	SI_PRD
25035050250000	33-15	8/1/1994	78.83	449.17	HOLW	SI_PRD
25073212850000	11-23	8/1/1994	78.17	975	HOHW	SI_PRD
25035071800000	35-13	9/1/2008	69.33	545	HOLW	Active_PRD
25073210610000	01-15	9/1/2008	69.17	328.83	HOLW	Active_PRD
25035050490000	34-11	9/1/2008	69.17	436.83	HOLW	Active_PRD
25035050420000	34-09	11/1/1988	69.00	685.33	HOHW	SI_PRD
25073211080000	01-13	2/1/1994	68.33	137.17	HOLW	SI_PRD
25073055300000	04-13	2/1/1994	68.00	139	HOLW	SI_PRD
25073055310000	10-01	1/1/2002	66.83	833	HOHW	SI_PRD
25073212180000	11-17	10/1/2002	65.67	389.5	HOLW	SI_PRD

Table A 7.4: **Categories applied to Last 6 Months Average and Production History Indicator.**

Class	Description	Explanation
HOHW	High Oil High Water	Oil and water above average
HOLW	High Oil Low Water	Oil above average, water below average
LOHW	Low Oil High Water	Oil below average, water above average
LOLW	Low Oil Low Water	Oil and water below average

Table A 7.5: List of candidates selected using "Total Liquid per foot of Perforated Interval"

Well Name	Hnet	MvAvg_Oil (bbl/m)	MvAvg_Water (bbl/m)	MvAvg_Water -cut (%)	MvAvg Fluid (bbl/m)	Well Satus	Tot.Fluid/ Perfs (bbl/m)
01-01	12	60.83	328.83	78.92	389.66	Active_PRD	32.47
01-09	38	87.00	436.67	77.50	523.67	Active_PRD	13.78
01-13	17	68.33	137.17	67.72	205.50	SI_PRD	12.09
01-15	29	69.17	328.83	76.82	398.00	Active_PRD	13.72
02-11	23	44.00	328.83	83.72	372.83	Active_PRD	16.21
02-13	8	32.83	250.33	87.03	283.16	SI_PRD	35.40
03-01	11	27.67	117.5	71.78	145.17	SI_PRD	13.20
03-20	9	105.83	367.67	77.72	473.50	SI_PRD	52.61
04-03	17	56.33	497.17	89.08	553.50	SI_PRD	32.56
04-07	19	136.83	1312.67	90.56	1449.50	SI_PRD	76.29
04-11	17	16.00	172.67	90.57	188.67	SI_PRD	11.10
04-13	18	68.00	139	68.34	207.00	SI_PRD	11.50
08-05	20	99.50	920.5	90.09	1020.00	SI_PRD	51.00
09-03	11	79.00	689.5	89.55	768.50	SI_PRD	69.86
09-05	23	323.33	731.5	67.55	1054.83	SI_PRD	45.86
09-11	10	62.50	443.33	85.40	505.83	SI_PRD	50.58
11-05	10	104.33	101.67	48.78	206.00	SI_PRD	20.60
11-11	12	133.00	125	48.50	258.00	SI_PRD	21.50
11-17	18	65.67	389.5	85.54	455.17	SI_PRD	25.29
11-18	18	89.33	604.67	87.09	694.00	SI_PRD	38.56
26-09	18	174.00	545	68.90	719.00	Active_PRD	39.94
26-15	22	44.00	653	90.93	697.00	Active_PRD	31.68
27-03	18	44.00	215.83	77.33	259.83	Active_PRD	14.44
27-05	16	52.33	329	81.27	381.33	Active_PRD	23.83
27-09	21	79.67	445.67	84.93	525.34	SI_PRD	25.02
28-15	15	90.17	697	88.47	787.17	SI_PRD	52.48
33-05	9	44.00	544.83	89.40	588.83	Active_PRD	65.43
33-11	10	39.83	144.67	78.35	184.50	SI_PRD	18.45
33-15	26	78.83	449.17	84.65	528.00	SI_PRD	20.31
34-05	26	205.83	834.67	79.51	1040.50	SI_PRD	40.02
34-09	3	69.00	685.33	56.70	754.33	SI_PRD	251.44
34-11	24	69.17	436.83	81.37	506.00	Active_PRD	21.08
34-16	16	114.00	475.17	80.49	589.17	SI_PRD	36.82
34-25	24	51.33	217.83	80.47	269.16	SI_PRD	11.22
34-26	22	86.83	215.83	64.07	302.66	Active_PRD	13.76
35-07	33	28.33	351.67	85.24	380.00	SI_PRD	11.52
35-13	23	69.33	545	84.40	614.33	Active_PRD	26.71

Table A 7.6: Candidates satisfying all the three selection criteria

01-09	**27-09**	**09-03**	**34-09**
04-13	**28-15**	**11-17**	**35-13**
08-05	**34-05**	**26-09**	

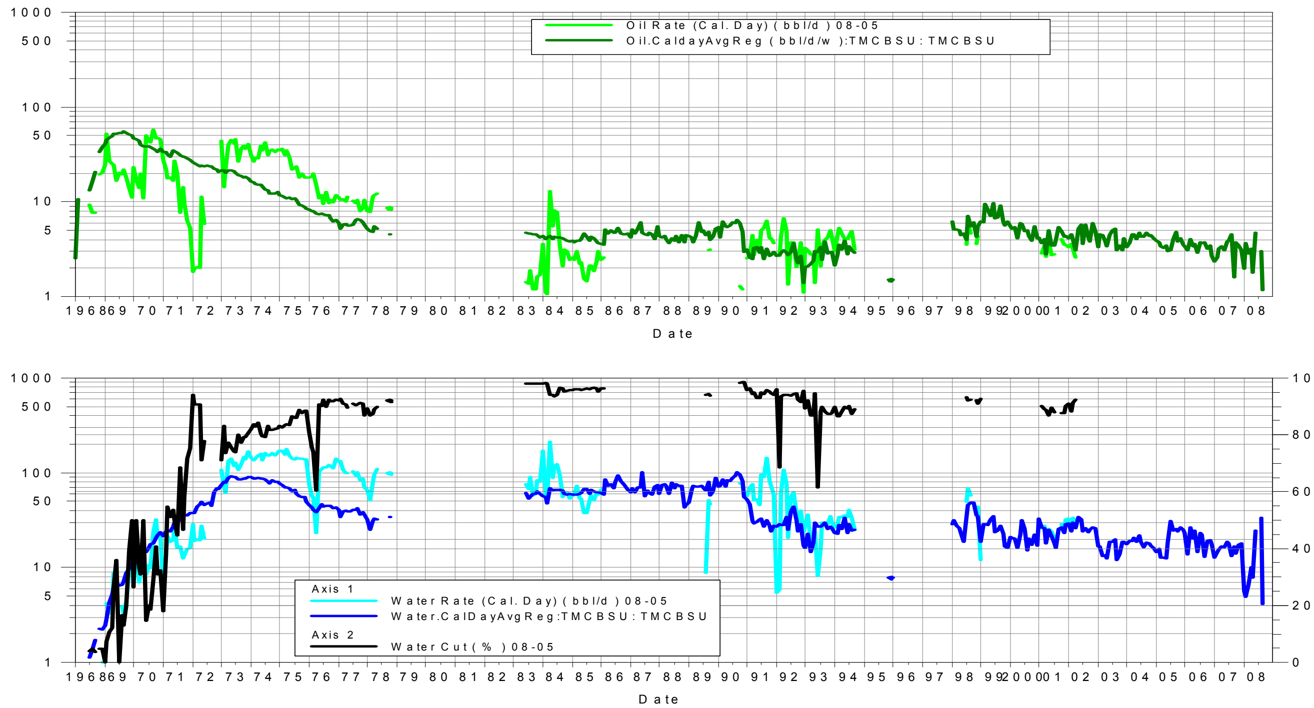
Table A 7.7: List of final selected candidates.

Wells	MvAvg Oil	Best 12 Months	Liq/ft Perf	Total	BLM	Historical Prd Behavior	Last Date Prd	Well Status OFM
02-11	0	1	1	2	X	HOHW	9/1/2008	OIL_ACT
03-15	1	1	0	2	X	HOHW	9/1/1994	OIL_SI
04-03	0	1	1	2	X	HOHW	8/1/1994	OIL_SI
08-05	1	1	1	3	X	HOHW	4/1/2002	OIL_SI
09-03	1	1	1	3	X	HOHW	4/1/2002	OIL_SI
11-17	1	1	1	3		HOHW	10/1/2002	OIL_SI
34-16	1	0	1	2	X	HOHW	12/1/2008	OIL_SI
01-01	0	1	1	2	X	HOLW	9/1/2008	OIL_ACT
01-09	1	1	1	3	X	HOLW	9/1/2008	OIL_ACT
11-05	1	0	1	2		HOLW	9/1/1994	OIL_SI
11-11	1	0	1	2	X	HOLW	8/1/1994	OIL_SI
26-09	1	1	1	3	X	HOLW	9/1/2008	OIL_ACT
27-05	0	1	1	2		HOLW	9/1/2008	OIL_ACT
27-09	1	1	1	3	X	HOLW	7/1/1994	OIL_SI
28-15	1	1	1	3	X	HOLW	8/1/1994	OIL_SI
34-05	1	1	1	3		HOLW	10/1/1978	OIL_SI
34-26	1	0	1	2	X	HOLW	9/1/2008	OIL_ACT
11-18	1	0	1	2		LOLW	8/1/1994	OIL_SI
35-13	1	1	1	3	X	LOHW	9/1/2008	OIL_ACT
26-15	0	1	1	2		LOLW	9/1/2008	OIL_ACT
02-13	0	1	1	2	X	LOHW	1/1/2008	OIL_SI
33-05	0	1	1	2	X	LOHW	9/1/2008	OIL_ACT
27-03	0	1	1	2		LOLW	9/1/2008	OIL_ACT
33-11	0	1	1	2	X	LOHW	10/1/2003	OIL_SI
02-03	0	1	0	1		NA	2/1/1986	OIL_SI
02-05	0	1	0	1		NA	6/1/1993	OIL_SI
27-13	0	1	0	1		NA	4/1/1994	OIL_SI

7.3.1 Production Plots for the 17 primary candidates (next 17 Figures)

The light green and light blue curves, represent the individual well performance, while the dark green and dark blue curves gives field averages.

Well UWI : 125001114488
Well Alias : 08-05



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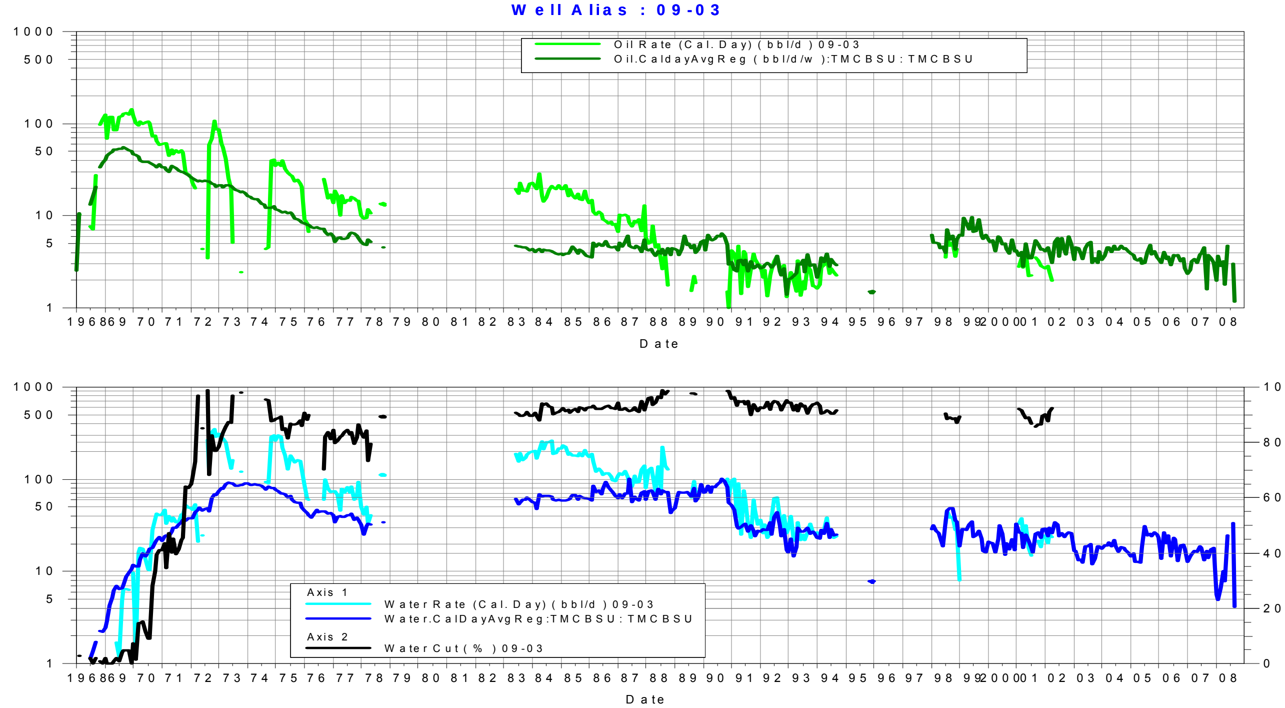
Well Alias : 09-03



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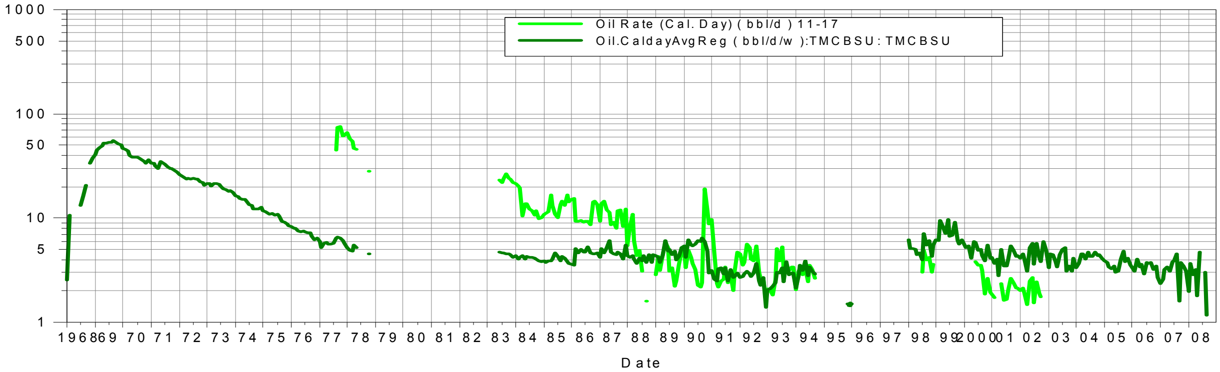
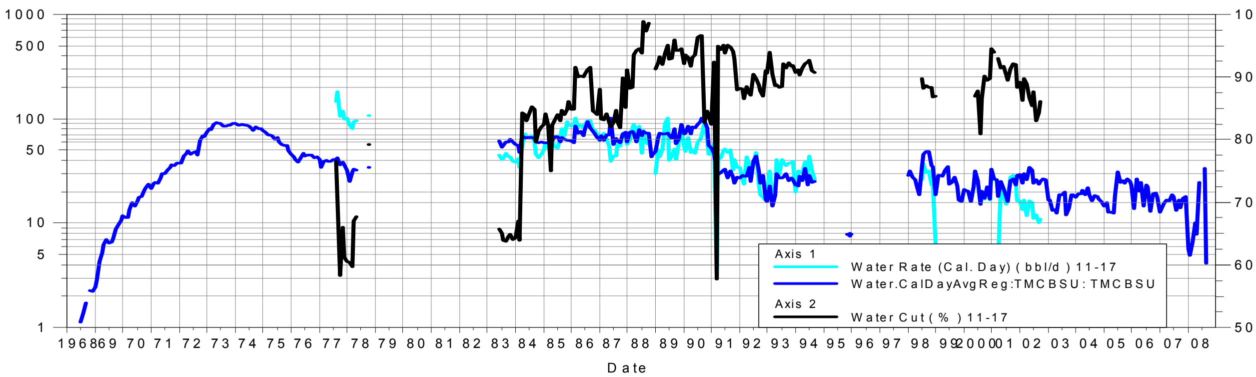
Well Alias : 11-17





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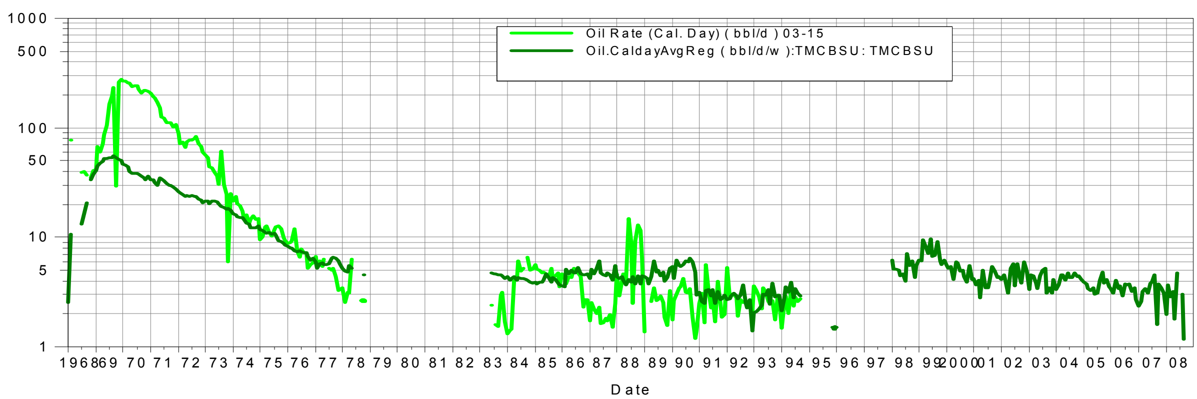

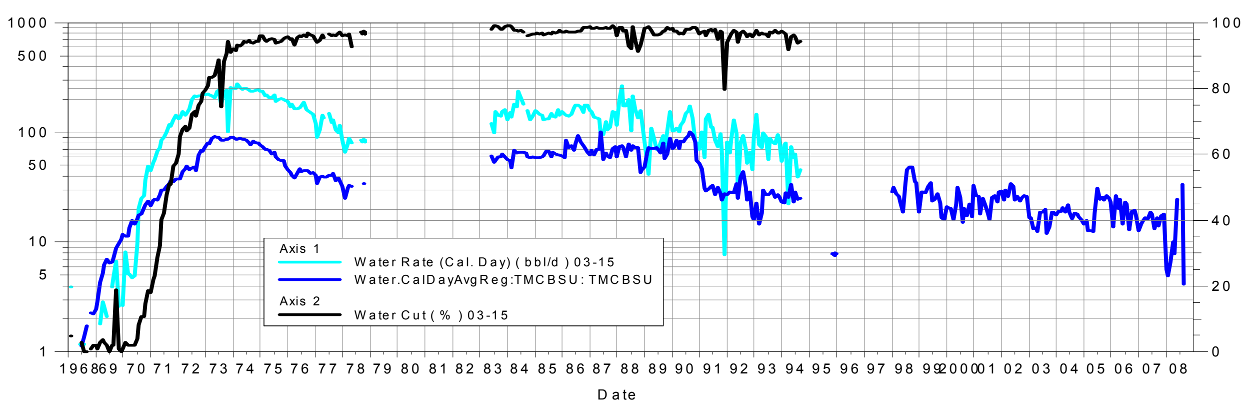

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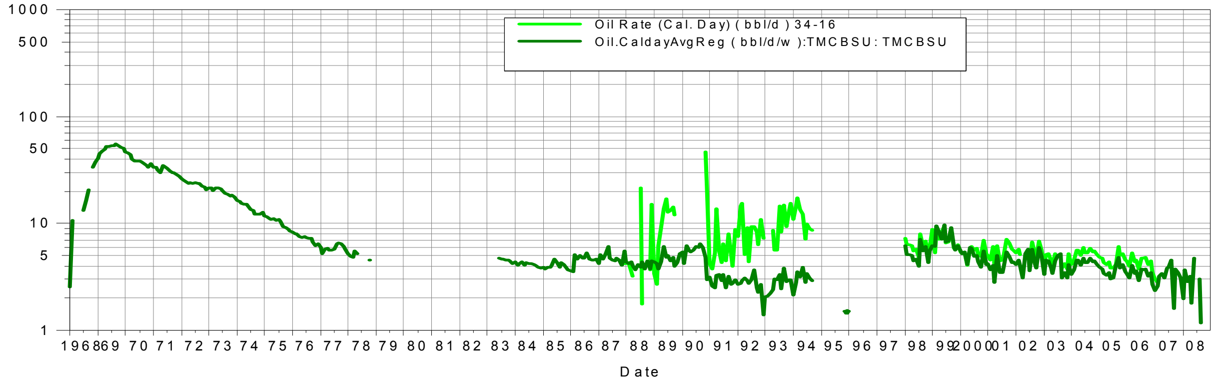

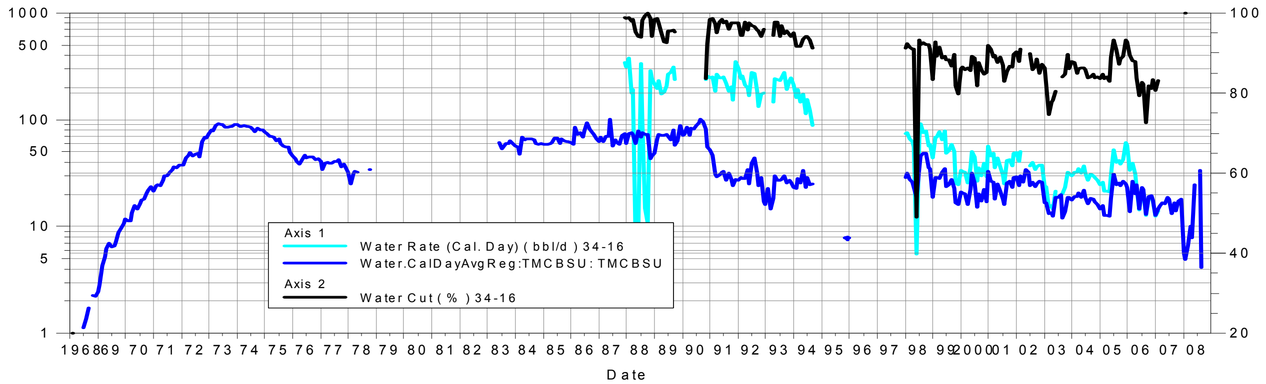

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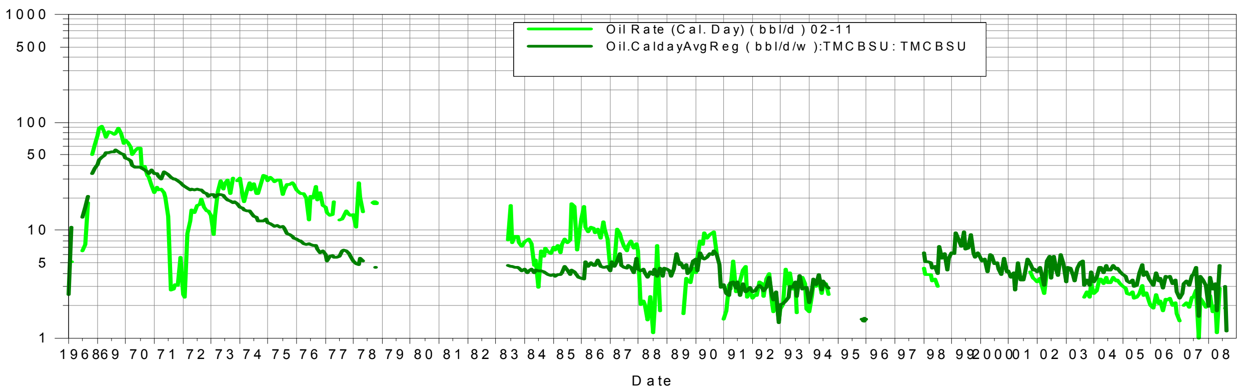
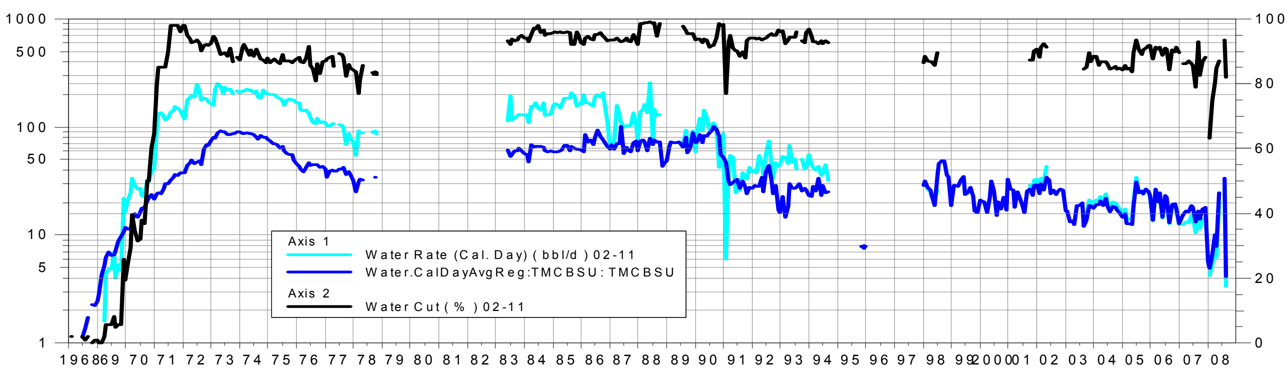
Well Alias : 02-11





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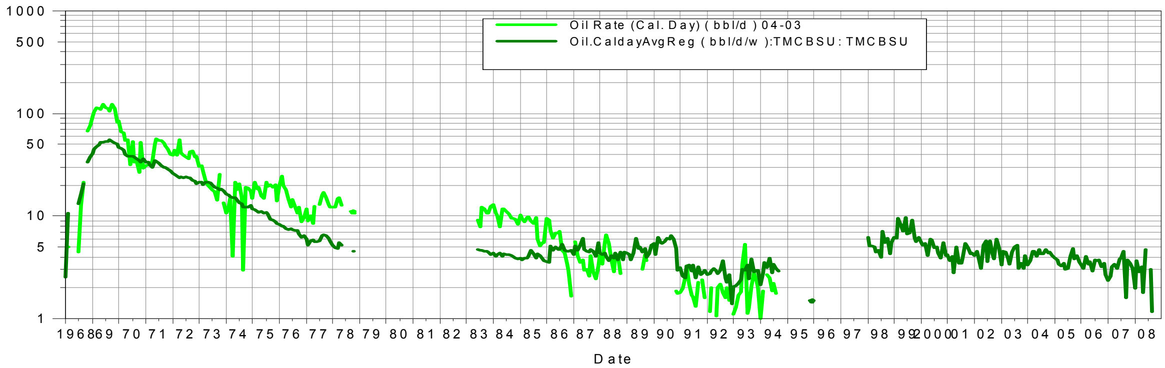
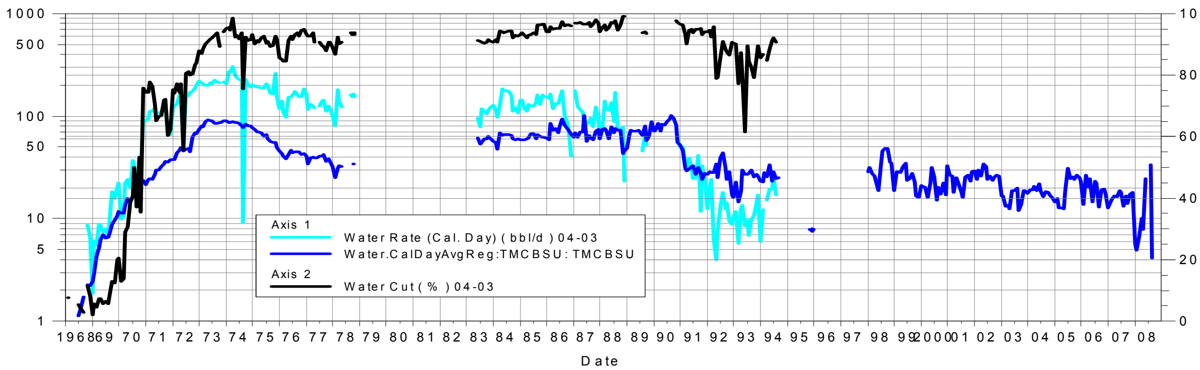
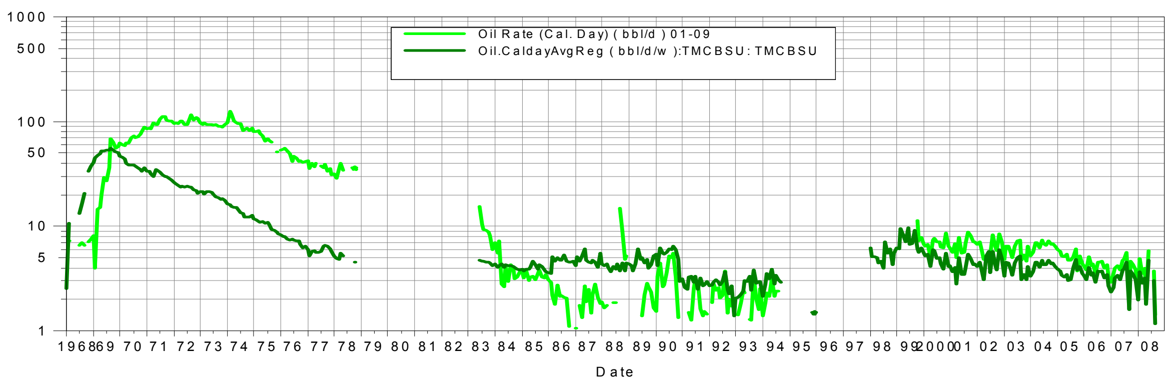
Well Alias : 04-03

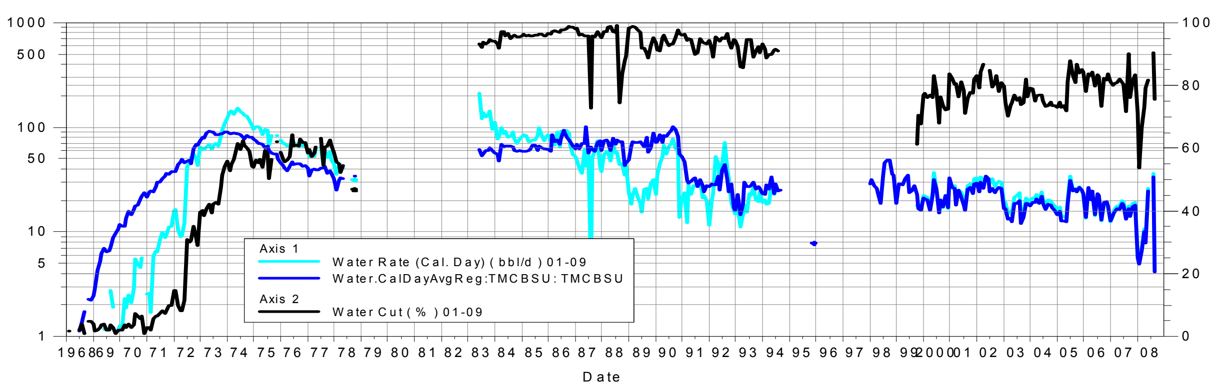




Well UWI : 125001114469

Well Alias : 01-09





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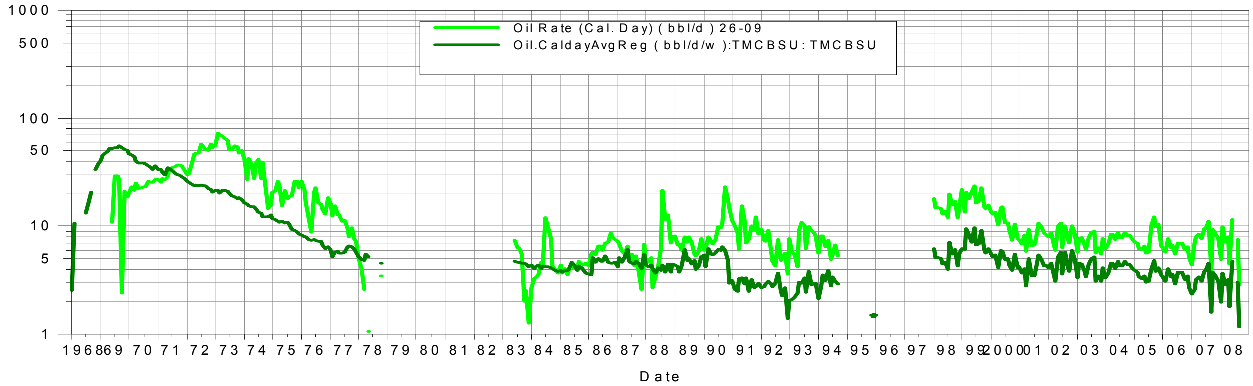

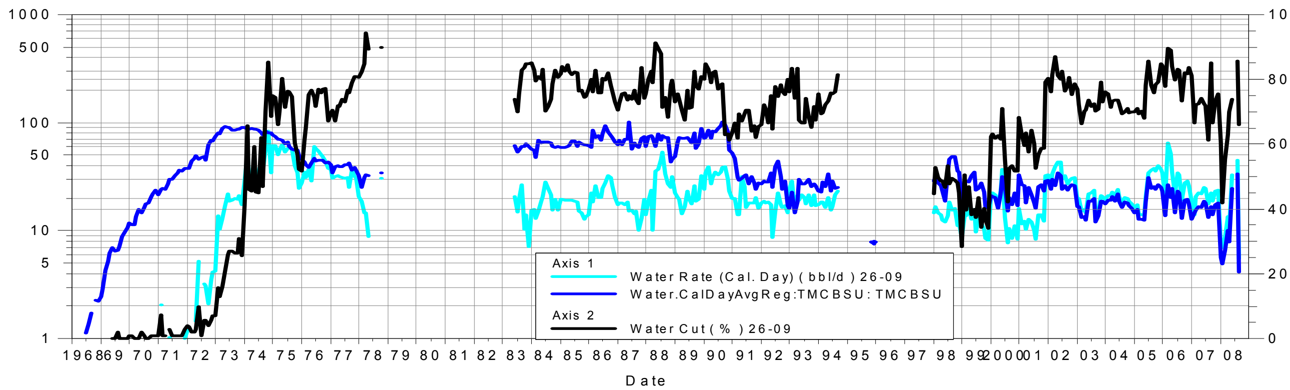

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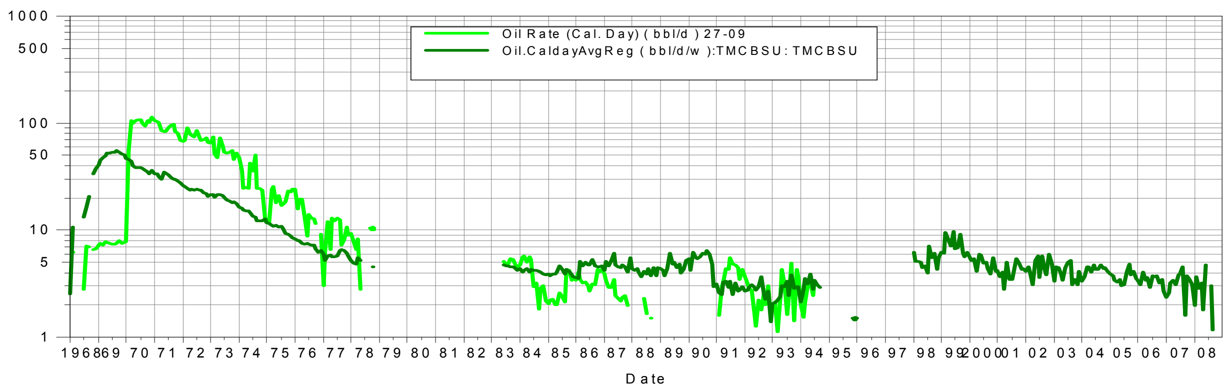
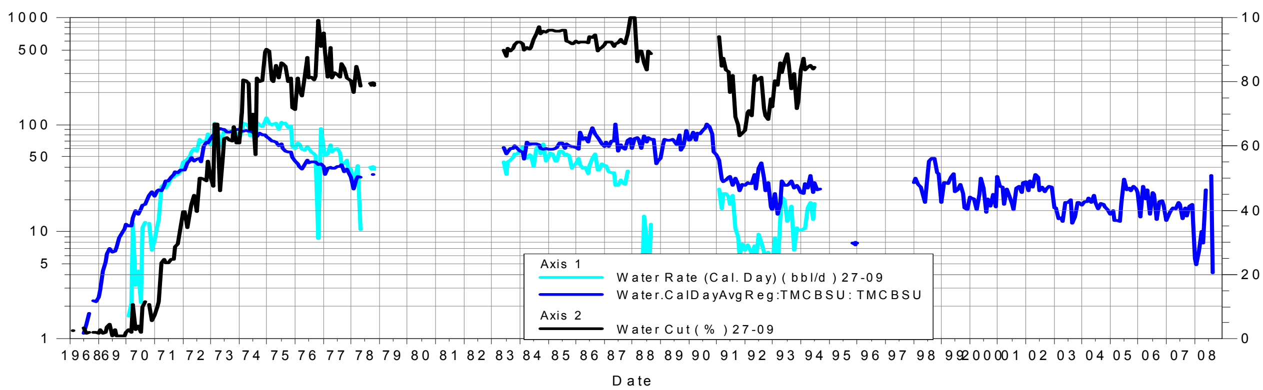
Well Alias : 27-09





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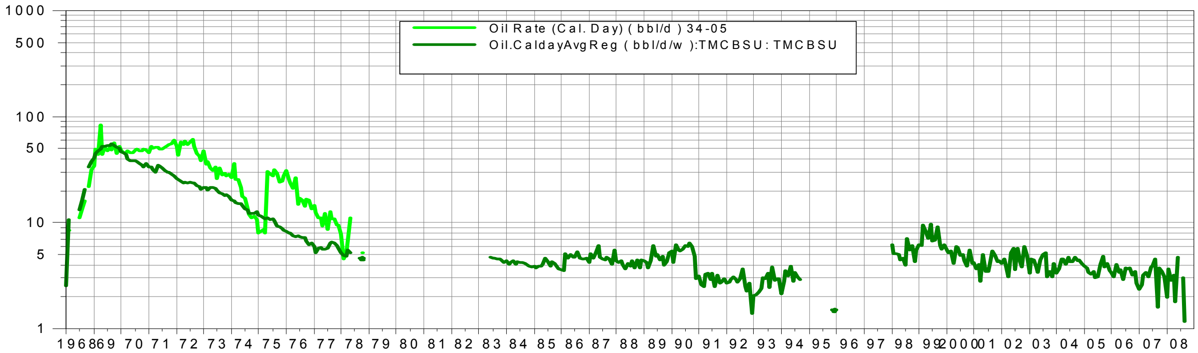
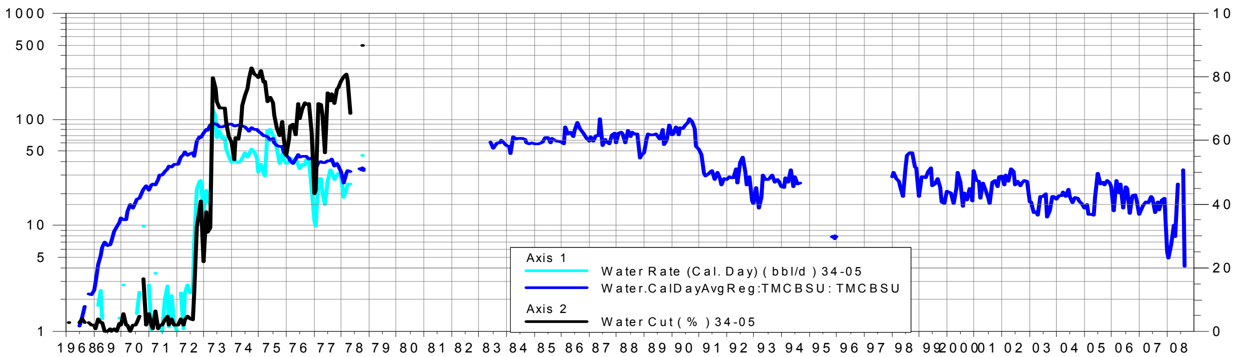
Well Alias : 34-05





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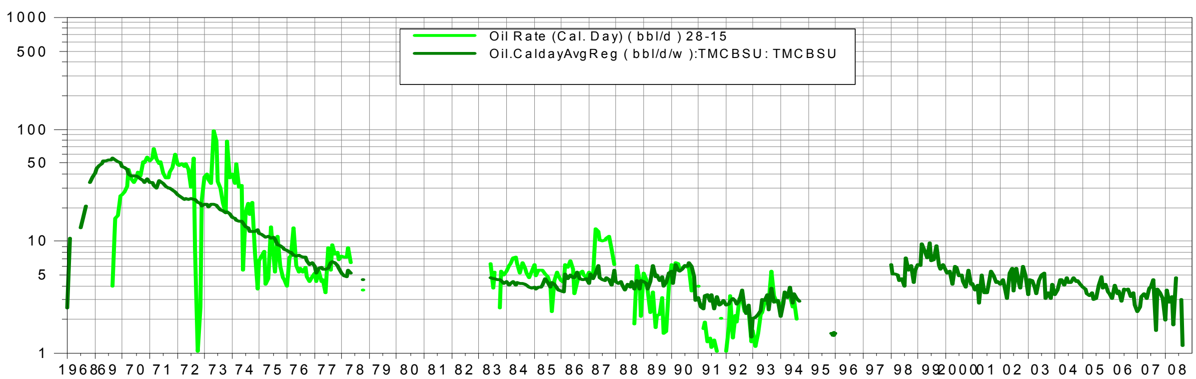
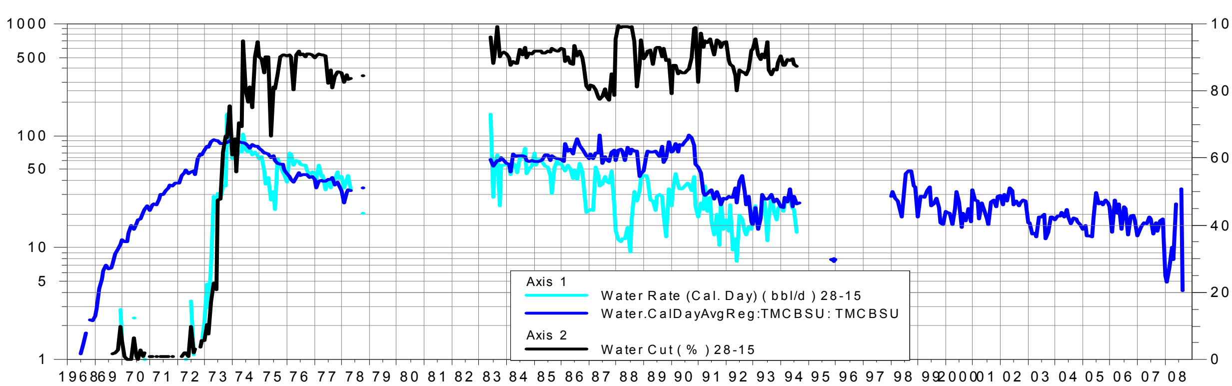
Well Alias : 28-15





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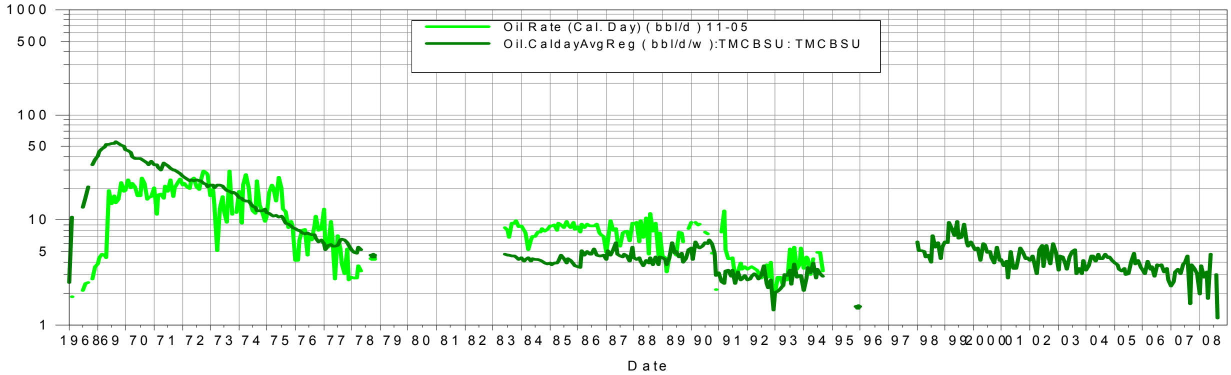
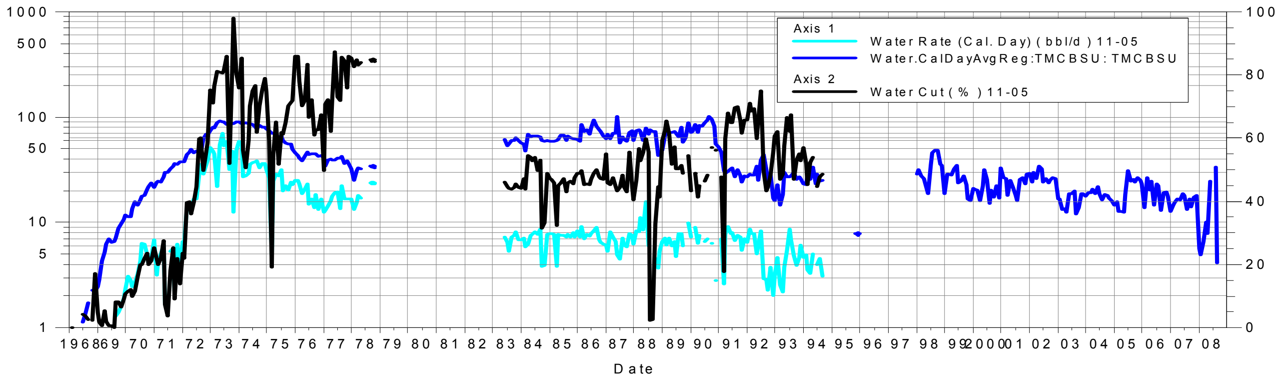
Well Alias: 11-05





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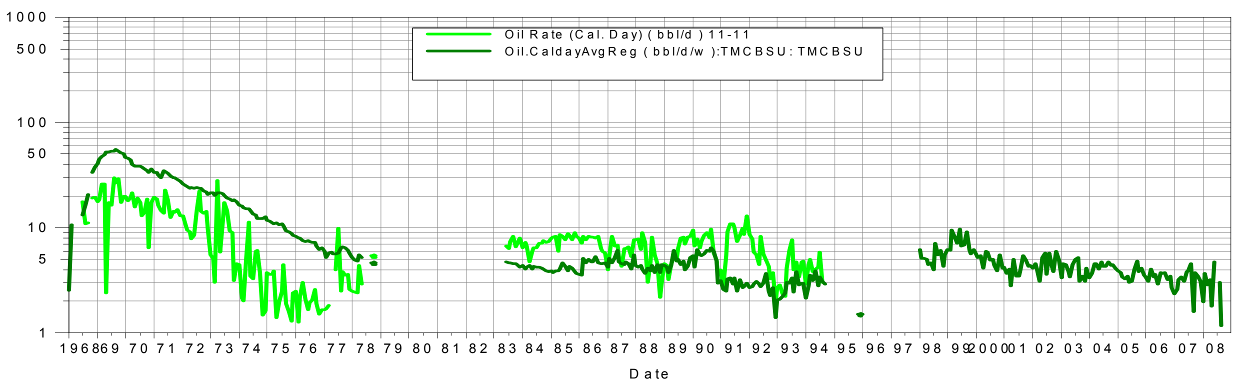

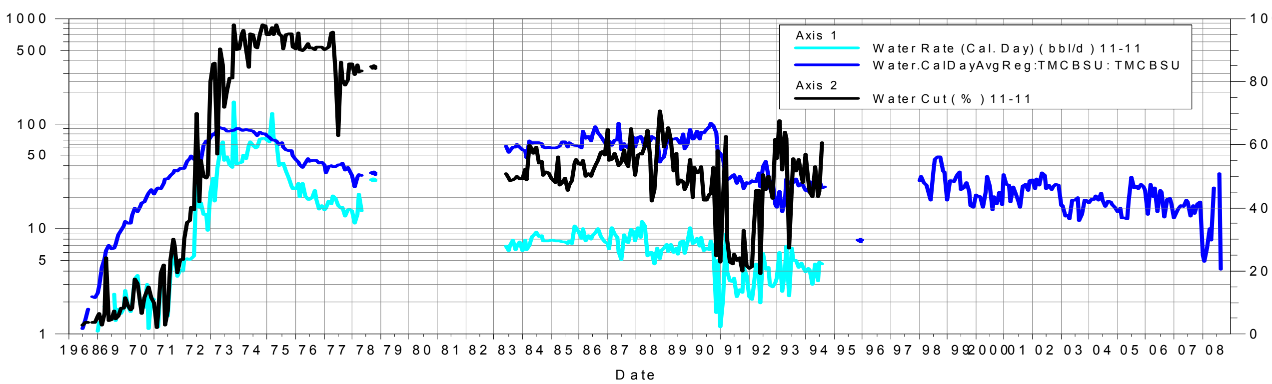

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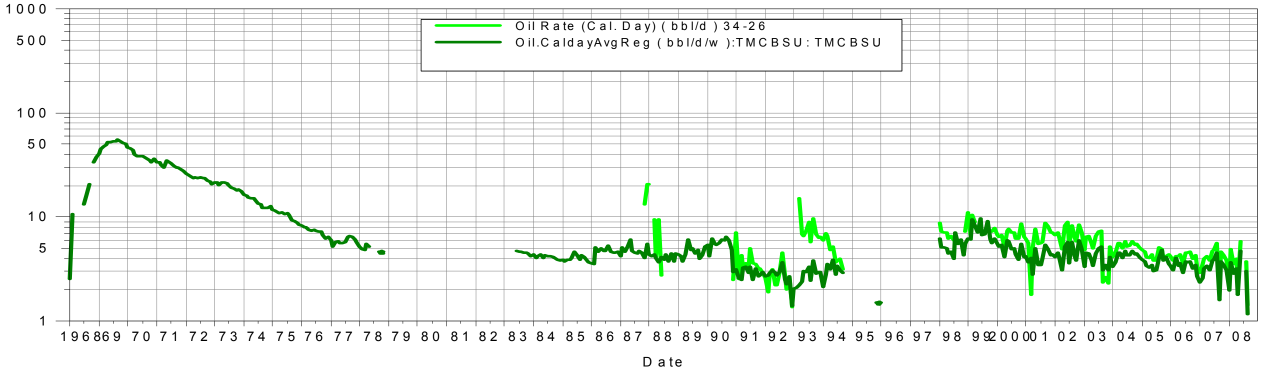
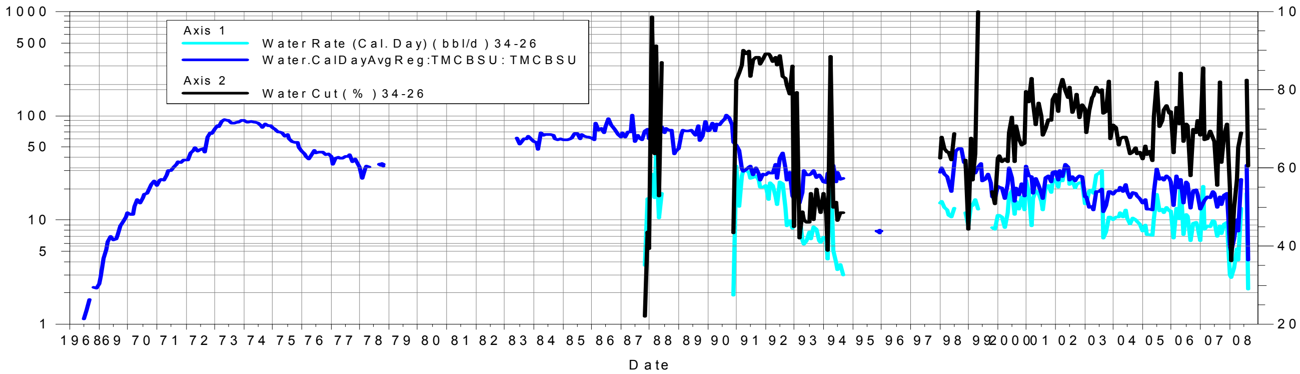
Well Alias : 34-26





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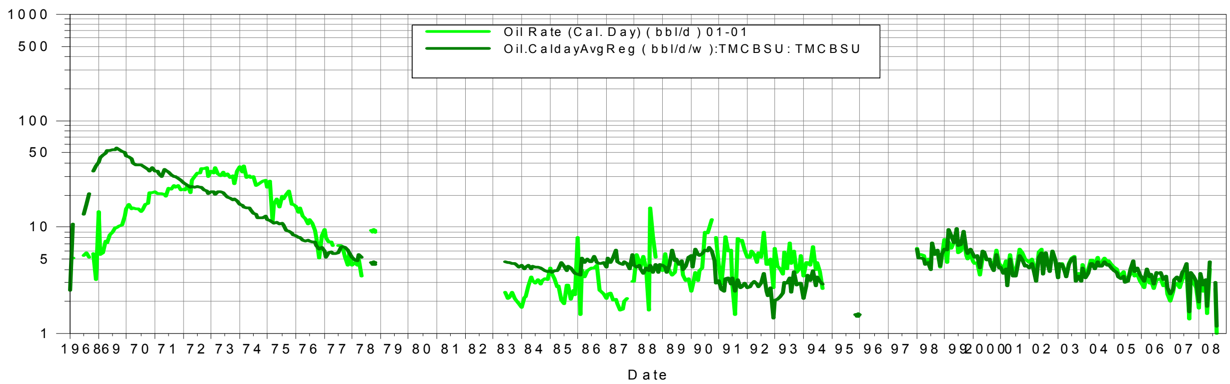
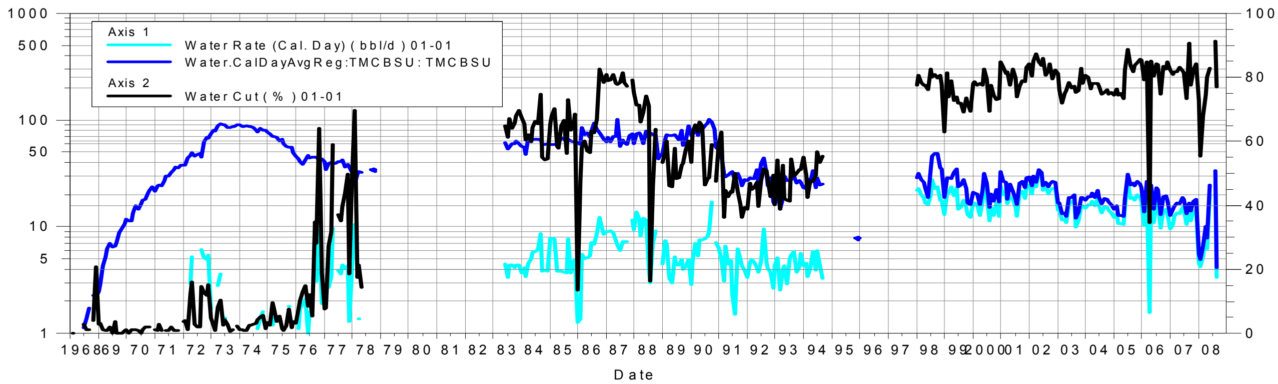
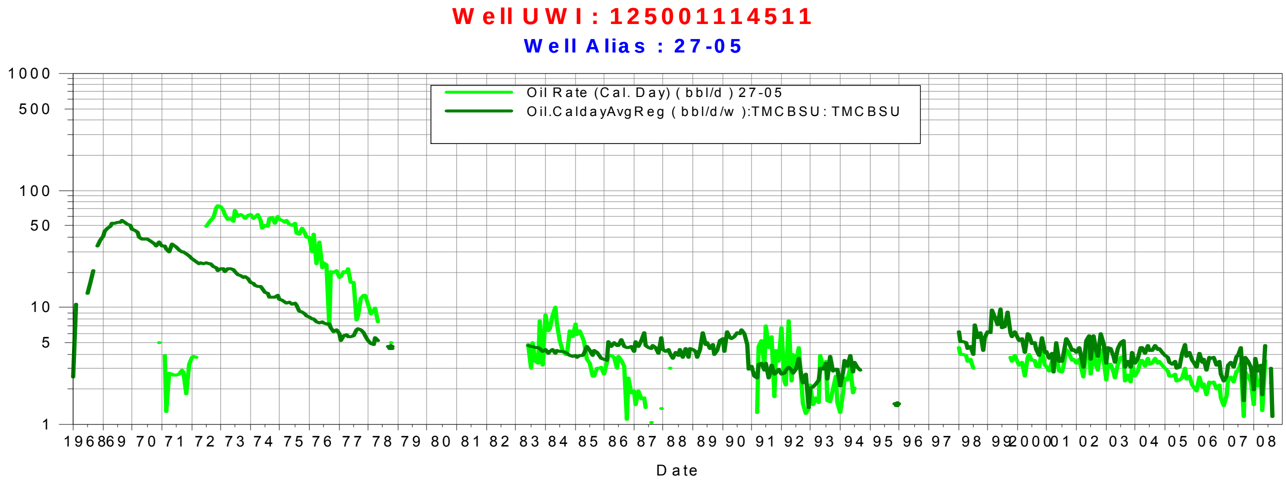
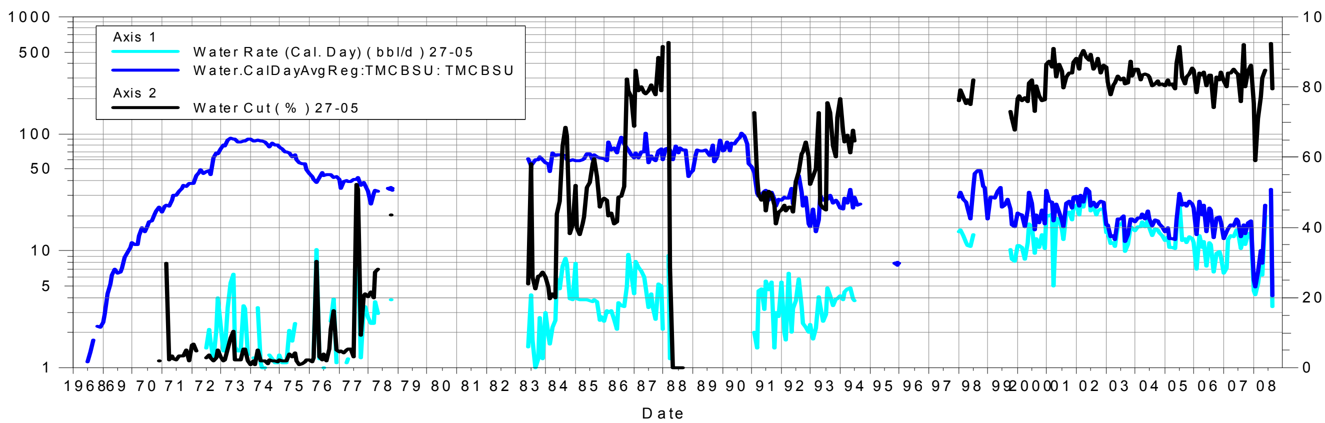
Well Alias : 01-01






Well UWI : 125001114511
Well Alias : 27-05
Oil Rate (Cal. Day) (bbl/d) 27-05
Oil.CaldayAvgReg (bbl/d/w):TMCBSU: TMCBSU
1000
500
100
50
10
5
1
1968 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 2000 01 02 03 04 05 06 07 08
Date


Axis 1
Water Rate (Cal. Day) (bbl/d) 27-05
Water.CalDayAvgReg:TMCBSU: TMCBSU
Axis 2
Water Cut (%) 27-05
1000
500
100
50
10
5
1
100
80
60
40
20
0
1968 69 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 2000 01 02 03 04 05 06 07 08
Date

7.4 Operations Review (Chapter 5)

Table A 7.8: Bottomhole Pressure Calculations based on measured fluid levels.

From OFM Database					From Client			Fluid Column	Hydrostatic Pressure (psi)		Est. Bottomhole Pressure	
Well Name	TD (ft)	Top_Perf (ft)	Bot_Perf (ft)	Perf Zone (ft)	PSI	Joints to Fluid	Fluid Level from surf (ft)	To mid-perf (ft)	Water	Oil	Est. BHP (w/water)	Est. BHP (w/oil)
01-01	3,260	3,182	3,194	12	-	102	3,162	26	11	10	11	10
01-09	3,180	3,100	3,138	38	-	Full		3,119	1,353	1,208	1,353	1,208
01-12	3,175				-	27	837					
01-12	3,175				125	Full					125	125
01-13	3,150	3,045	3,062	17	-	35	1,085	1,969	854	762	854	762
01-15	3,120	3,001	3,030	29	-	14	434	2,582	1,120	999	1,120	999
02-05	3,260	3,185	3,199	14	40	57	1,767	1,425	618	552	658	592
02-13	3,072	3,018	3,026	8	225	Full		3,022	1,311	1,170	1,536	1,395
02-15	3,176	3,102	3,125	23	-	Full		3,114	1,350	1,205	1,350	1,205
03-01	3,258	3,208	3,219	11	-	37	1,147	2,067	896	800	896	800
03-13	3,278	3,062	3,075	13		Full		3,069	1,331	1,188	1,331	1,188
03-15	3,325	3,220	3,244	24	55	Full		3,232	1,402	1,251	1,457	1,306
03-20	3,304	3,191	3,200	9	-	8	248	2,948	1,278	1,141	1,278	1,141
08-05	3,535	3,442	3,462	20	-	9	279	3,173	1,376	1,228	1,376	1,228
09-11	3,471	3,376	3,386	10	-	6	186	3,195	1,386	1,237	1,386	1,237
09-24	3,500	3,412	3,424	12	-	9	279	3,139	1,361	1,215	1,361	1,215
10-01	3,379	3,300	3,310	10	90	Full		3,305	1,433	1,280	1,523	1,370
10-03	3,270	3,156	3,156	0	275	Full		3,156	1,369	1,222	1,644	1,497
10-15	3,440				-	19	589					
11-02	3,188				-							
11-05	3,170	3,066	3,076	10	300	Full		3,071	1,332	1,189	1,632	1,489
11-11	3,235	3,164	3,176	12	265	Full		3,170	1,375	1,227	1,640	1,492
11-17	3,250	3,132	3,150	18	165	Full		3,141	1,362	1,216	1,527	1,381
11-18	3,241	3,096	3,114	18	225	Full		3,105	1,347	1,202	1,572	1,427
15-03	3,370				-	8	248					
26-09	3,407	3,316	3,334	18	-	106	3,286	39	17	15	17	15
26-15	3,354	3,222	3,244	22	-	19	589	2,644	1,147	1,024	1,147	1,024
27-03	3,530	3,434	3,452	18	-	111	3,441	2	1	1	1	1
27-05	3,475	3,375	3,391	16	125	Full		3,383	1,467	1,310	1,592	1,435
27-15	3,391				-	Full						
28-05	3,557	3,471	3,502	31	-	33	1,023	2,464	1,068	954	1,068	954
28-15	3,685	3,590	3,605	15	20	3	93	3,505	1,520	1,357	1,540	1,377
29-09					-	4	124					
33-15	3,450	3,353	3,379	26	-	3.5	109	3,258	1,413	1,261	1,413	1,261
34-11	3,430	3,342	3,366	24	-	102	3,162	192	83	74	83	74
34-11	3,430	3,342	3,366	24	-	101	3,131	223	97	86	97	86
34-13	3,319				-		-					
34-16	3,409	3,314	3,330	16	-	59	1,829	1,493	647	578	647	578
34-26	3,450	3,338	3,360	22	-	116	3,596					
35-03	3,275	3,196	3,218	22	-	Full		3,207	1,391	1,242	1,391	1,242
35-13	3,340	3,204	3,227	23	120	8	248	2,968	1,287	1,149	1,407	1,269

Calculations:

BHP = Surf. Pressure + Fluid Column (ft) x 0.052 x Fluid Density (lbs/gal)
BHP = Surf. Pressure + Fluid Column (ft) x 0.433 psi/ft

Density of Water: 8.34 lb/gal
Conv. Factor: 0.052 0.4337 psi/ft

Density of oil: 7.4455 lb/gal (API = 27)
0.3872 psi/ft

Density oil = S.G. oil * density of water
S.G. oil = 141.5 / (API + 131.5)
API in TMCBSU: 24-30

Table A 7.9: Potential Incremental Oil estimates

Well Name	Status	TD (ft)	Top_Perfs (ft)	Bot_Perf (ft)	Perf Zone (ft)	CP PSI	Est. Static__Pressure (@ .44/psi/ft	Pwf	DeltaP	6 Months Moving Avg BFPD	6 Months Moving Avg Oil_Cut	PI (BFPD/PSI)	@ max fluid after flood _ BFPD	Incremental BFPD @ 0 PSI ¯ /f	Est Inc Oil	PU_Size	PU Max Capcity
01-01	active	3260	3,182	3,194	12	0	1405	11	1394	12	17%	0.0086	42	0.10	0	160	170
01-09	active	3180	3,100	3,138	38	0	1381	1353	28	16	18%	0.5700	69	69.00	12	114	142
01-13	down	3150	3,045	3,062	17	0	1347	854	494	7	35%	0.0142	10	10.00	4	114	142
01-15	active	3120	3,001	3,030	29	0	1333	1120	214	12	19%	0.0562	30	30.00	6	114	142
02-05	active	3260	3,185	3,199	14	40	1408	618	790	1	46%	0.0013	8	0.78	0	114	142
03-20	active	3304	3,191	3,200	9	0	1408	1278	130	16	22%	0.1233	103	103.00	23	160	170
26-09	active	3407	3,316	3,334	18	0	1467	17	1450	22	26%	0.0152	60	0.26	0	160	170
26-15	active	3354	3,222	3,244	22	0	1427	1147	281	21	7%	0.0748	40	40.00	3	160	170
27-03	active	3530	3,434	3,452	18	0	1519	1	1518	8	19%	0.0053	20	0.00	0	57	51
27-05	active	3475	3,375	3,391	16	125	1492	1467	25	12	15%	0.4819	25	25.00	4	57	51
28-05	down	3557	3,471	3,502	31	0	1541	1068	473	6	25%	0.0127	13	13.00	3	160	170
28-15	down	3685	3,590	3,605	15	20	1586	1520	66	25	12%	0.3767	41	41.00	5	160	170
33-15	down	3450	3,353	3,379	26	0	1487	1413	74	17	15%	0.2296	48	48.00	7	160	170
34-11	active	3430	3,342	3,366	24	0	1481	83	1398	16	15%	0.0114	40	0.95	0	160	170
34-26	active	3450	3,338	3,360	22	0	1478	0	1478	10	31%	0.0068	30	0.00	0	160	170
35-13	active	3340	3,204	3,227	23	120	1420	1287	133	19	12%	0.1429	102	102.00	12	160	170
															79		

Figure A 7.6: Portable test unit that enables single-well tests.

Figure A 7.7: Skid Mounted Pumping Unit.

8 REFERENCES

[1] Figure 3.1 and Figure 3.2 Source: "Blackfeet Indian Reservation", Blackfeet nation. http://www1.eere.energy.gov/tribalenergy/guide/pdfs/blackfeet.pdf

[2] Ditton P.J., Manchester D., Seidlitz A.L.: "Two Medicine Cut Bank Sand Unit Analysis", May 8, 1996.