

IMPLEMENTING A NOVEL CYCLIC CO₂ FLOOD IN PALEOZOIC REEFS

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ABSTRACT

Recycled CO₂ is being used in this demonstration project to produce bypassed oil from the Silurian Dover 35 Niagaran pinnacle reef located in Otsego County, Michigan. CO₂ injection in the Dover 35 field into the Salling-Hansen 4-35A well began on May 6, 2004. A second injection well, the Salling-Hansen 1-35, commenced injection in August 2004. Oil production in the Pomerzynski 5-35 producing well increased from 9 BOPD prior to operations to an average of 165 BOPD in December, 2004 and has produced at an average rate of 61 BOPD (Jan-Dec, 2005). The Salling-Hansen 4-35A also produced during this reporting period an average of 29 BOPD. These increases have occurred as a result of CO₂ injection and the production rate appears to be stabilizing. CO₂ injection volume has reached approximately 2.18 BCF.

The CO₂ injection phase of this project has been fully operational since December 2004 and most downhole mechanical issues have been solved and surface facility modifications have been completed. It is anticipated that filling operations will run for another 6-12 months from July 1, 2005. In most other aspects, the demonstration is going well and hydrocarbon production has been stabilized at an average rate of 57 BOPD (July-Dec, 2005). Our industry partners continue to experiment with injection rates and pressures, various downhole and surface facility mechanical configurations, and the huff-n-puff technique to develop best practices for these types of enhanced recovery projects.

Subsurface characterization was completed using well log tomography and 3D visualizations to map facies distributions and reservoir properties in the Belle River Mills, Chester 18, Dover 35, and Dover 36 Fields. The Belle River Mills and Chester 18 fields are being used as type-fields because they have excellent log and/or core data coverage. Amplitude slicing of the log porosity, normalized gamma ray, core permeability, and core porosity curves are showing trends that indicate significant heterogeneity and compartmentalization in these reservoirs associated with the original depositional fabric and pore types of the carbonate reservoir rocks. Accumulated pressure data supports the hypothesis of extreme heterogeneity in the Dover 35. Some intervals now have pressure readings over 2345 psig (April 29, 2005) in the A-1 Carbonate while nearby Niagaran Brown intervals only show 1030 psig (March 7, 2005). This is a pressure differential over 1300 psig and suggests significant vertical barriers in the reef, consistent with the GR tomography modeling.

Digital and hard copy data have been compiled for the Niagaran reefs in the Michigan Basin, including a detailed summary of 20 fields in the vicinity of the demonstration well. Technology transfer took place through technical presentations regarding visualization of the reservoir heterogeneity in these Niagaran reefs. Oral presentations were given at two Petroleum Technology Transfer Council workshops, a Michigan Oil and Gas Association Conference, a Michigan Basin Geological Society meeting, and the Eastern American Association of Petroleum Geologist's Annual meeting. In addition, we met with our industry partners several times during the first half of 2005 to communicate and discuss the reservoir characterization and field site aspects of the demonstration project. A technical paper was published in the April 2005 issue of the AAPG Bulletin on the characterization of the Belle River Mills Field.

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Figure 39. Dover 35 daily oil production and cumulative CO₂ injection. The 1-35 produced approximately 12 BOPD before conversion to injection.

1.0 EXECUTIVE SUMMARY

Goals and Results

The primary project goals are to:

1. Demonstrate through a field trial that significant quantities of by-passed hydrocarbons can be recovered from pinnacle reefs using a novel CO₂ cycling technology. The CO₂ came from nearby Antrim gas processing facilities resulting in the added benefit of the CO₂ being sequestered rather than vented to the atmosphere.
2. Use log-curve amplitude slicing and well log tomography to develop a 3D digital model of a pinnacle reef.
3. Inventory the Michigan Basin for abandoned or shut-in reefs that are suitable candidates for similar recovery efforts. Compile pertinent engineering and geological characteristics in digital format.
4. Pass the results, economics, and data obtained from the demonstration project along to independent producers via an aggressive technology transfer program.

Field Demonstration

We began injecting CO₂ into the Niagaran reservoir (A1 Carbonate) in the Dover 35 field in Otsego County, Michigan on May 6, 2004 using the Salling-Hansen 4-35A well (Figures 1, 2, 3 and 4). On August 1, 2004 injection began into a second well, the Salling-Hansen 1-35; the 1-35 was a producer until June, 2004. Response was measured in the Pomerzynski 5-35 in August, 2004 and by late September the 5-35 was producing approximately 90 barrels of oil per day and attempting to flow (prior production was approximately 9 BOPD; Figures 5 and 6). Our industry partners (Jordan Exploration Company, LLC and CO₂ supplier, Core Energy, LLC) pulled the pump and rods from the 5-35 in November 2004 and the well was flowing at rates up to approximately 300 barrels of oil per day in December 2004 (Figure 5). Wax deposition, typical in these types of wells during either primary or enhanced oil recovery operations, is occurring in the 5-35 flowline and sometimes prevents 24 hour run times. In January 2005 surface facilities were modified to handle greater fluid volumes and pressures from the 5-35 well. The 5-35 well was worked over to raise the tubing above the perforations to improve production performance. The well averaged 91 BOPD from January through June of 2005, and is presently flowing an average of 31 BOPD (July-December, 2005) as compared to 9 BOPD prior to CO₂ injection.

The field demonstration project was shifted three miles to the west to the Dover 35 Niagaran Field from the Charlton 6 Field based upon CO₂ availability and flooding schedules (refer to Figure 1b). The change in the demonstration well site was previously approved by the DOE. Contract negotiations between our industry partner (Jordan Exploration Company, LLC) and the CO₂ supplier (Core Energy, LLC) reached completion in early 2004. The State of Michigan and the Envi-

ronmental Protection Agency inspected facilities and issued orders granting our industry partner's application to begin the project in March-April 2004.

Figures 3 and 4 are location maps for the Dover 35 Field area. The Salling-Hansen #4-35A (northwest well in field, blue triangle, Michigan permit number 29995) is being used to inject recycled CO₂ from the Dover 36 and/or Dover 33 fields and/or compressed Antrim waste CO₂ into the uppermost Dover 35 Niagaran (A1 Carbonate) reservoir. Injection rates are less than anticipated into the 4-35A well (averaging 1.3 MMCF per day versus the anticipated 5 MMCF per day) with cumulative injection of 430 MMCF through July 11, 2005 (Figure 6). The lower injection rates were due to two causes: one, in places, the formation would not take more CO₂ due to unexpected tight zones (heterogeneities); and second, because the old pipe in the injection wells could not take the higher pressures without failure. In May of 2005, the 4-35A well was reconfigured to be either a producer or injector well. It has been a producing well since then (averaging 31 BOPD from July through Dec, 2005), except for two short time frames in July and August of 2005 where the well was switched back to CO₂ injection.

Injection rates for the Salling-Hansen #1-35 well have averaged 3.01 MMCF per day (during 2005) with cumulative injection of 1,770 MMCF through December 31, 2006 (Figure 7). Figures 6 and 7 show the daily CO₂ injection volumes for the 4-35A and the 1-35 through February 2006; facility downtime resulted in several time frames of zero CO₂ injection.

Salling-Hansen 4-35A

CO ₂ Injection:	May 6, 2004 - Dec. 29, 2004 (305.7 MMCF)
CO ₂ Injection:	Feb. 1, 2005 - April 27, 2005 (119 MMCF)
Oil Production:	May 27, 2005 - July 8, 2005 (925 BBLs)
CO ₂ Injection:	July 9, 2005 - July 11, 2005 (5.7 MMCF)
Oil Production:	July 12, 2005 - Dec. 31, 2005 (5420 BBLs)
CO ₂ Injection:	Aug 16, 2005 - Aug. 24, 2005 (12.3 MMCF)
Total CO ₂ injection:	443 MMCF

Salling-Hansen 1-35:

CO ₂ Injection:	Aug. 1, 2004 - Oct. 17, 2004 (342 MMCF)
CO ₂ Injection:	Oct. 17, 2004 - Feb. 1, 2005 (438 MMCF)
CO ₂ Injection:	March 9, 2005 - July 11, 2005 (446 MMCF)
CO ₂ Injection:	July 12, 2005 - Dec. 31, 2005 (543 MMCF)

Total CO₂ injection: 1770 MMCF

Analogs

Amplitude slice animations and 3D models and visualizations have been completed that show the distribution of the gamma ray, core porosity and core permeability amplitudes in the Belle River Mills reef. A peer reviewed technical paper was published in the April 2005 issue of the Bulletin of the American Association of Petroleum Geologists. The AAPG is also working with us to create an internet datapage through their website that readers may access to view the actual animations referred to in the article.

Significant progress has been made modeling the Chester 18 and the Dover 35 and 36 Fields and preliminary well log tomography animations of the gamma ray and porosity have been created. Modeling results for these fields were reported in the first semi-annual technical report for 2004 (project period January 1, 2004 - June 30, 2004).

Data Compilation

Engineering data continues to be compiled for Niagaran reefs in the Michigan Basin from hard copy records of the Michigan Department of Natural Resources (DNR). A digital production database from January 1982 through July 2003 has been manipulated to create a digital report of the production for all Niagaran Fields. The DNR database has been combined with the newly compiled annual historical production data for Michigan oil and gas fields from 1932 to 1981; these digital data were compiled from printed hard copy reports. We are now able to produce annual decline plots by field from initial production to the present day for most of the oil and gas fields in Michigan.

A separate digital database was created from the Michigan Tech well databases showing wells that were cored in the Niagaran in the Michigan Basin. A similar spreadsheet listing wells with Niagaran cores in the Michigan Basin is located on the Michigan Basin Core Research Laboratory web site at Western Michigan University [<http://www.wmich.edu/geology/corelab/corelab.htm>]. The Michigan Department of Natural Resources historical paper copy pressure reports for the Niagaran Reef trend have been obtained and initial reservoir pressure data from these reports has been entered into a pressure database.

New Findings

One new key finding is that there are significant reservoir architecture variations in these carbonate reef reservoirs. We know from our 3D visualization and well log tomography work that the best permeability (connectivity) and porosity (storage capacity) does not always coincide in these reservoirs. New bottom hole pressure buildup data from wells in the Dover 35 Field is also supporting these observations from the reservoir modeling. Static bottom hole pressure data acquired in the 1-35 for the A1 Carbonate and the Brown Niagaran originally diverged when injection was initiated into the A1 Carbonate, but is now starting to converge (Figure 7) due to decreases in pressure that occurred during facility workovers and testing periods. Concurrently, the static bottom hole pressure for the Brown Niagaran in the 5-35 producer has increased along a steeper slope but is delayed in time.

Additional key findings include the observation that the distribution of the log porosity in the Dover 35 and Chester 18 Reefs appears to be similar to the distribution of the core porosity and core permeability in the Belle River Mills reef. In addition, the gamma ray distribution trends in all three reefs appear similar although the Dover 35 field is relatively small (only 4 well penetrations) in comparison to the other fields. These are important observations and are significant because it means we may be able to use well log tomography visualization techniques to map the distribution of permeability and porosity in reefs without core data (most Niagaran Reef wells have at least a gamma ray and porosity log curve). By scaling the areal distribution of this relationship (calibrated with additional analogs) we may be able to predict the likely distribution of the permeability and porosity in the Dover 35 Field as well as other Niagaran reefs.

Another earlier key finding that has emerged from the continuation of our 3D visualization work during the annual reporting period is that it appears that the best permeability and porosity in the Niagaran Reefs are not necessarily coincident. In other words, high permeability does not always indicate high porosity nor does low permeability always indicate low porosity. It appears that the distribution of reef permeability and porosity is controlled by the original depositional fabric of the carbonate rocks (i.e., vuggy, pinpoint, moldic fabrics, among others) and that subsequent diagenesis has only partially modified this original depositional and rock property fabric (i.e., dolomitization of the original limestones in the Belle River Mills, Chester 18, and Dover 33 fields has not completely removed this original fabric). The Dover 35 and 36 fields are reported in sample descriptions to be composed predominately of limestone in the Brown Niagaran, although, the A1 Carbonate porosity zone is described as being composed of 100% dolomite.

A third finding is that high-resolution images of the larger multi-well Niagaran Fields can be obtained using well log tomography. In comparison, 3D seismic is more costly and does not achieve the high vertical resolution found in the well log curves; together well log tomography and 3D seismic can yield high vertical resolution and high lateral resolution reservoir images. Tomography of the Belle River Mills and Chester 18 fields shows that these fields are really composed of five and two individual reefs or carbonate sediment production centers, respectively, that have coalesced to form what has been called a single reef field. Reservoir engineering data from previous studies by the operator in the case of the Chester 18 Field supports the interpretation of two distinct reefs or pressure/production compartments. The gamma ray, core porosity, and core permeability amplitude slicing at Belle River Mills show five likely areal subdivisions to the field.

Finally, we show how to use the pinnacle reef fields that have been on CO₂ injection to predict performance of fields that may be candidates for CO₂ injection. In particular, we found that the primary and secondary production profiles for Dover 33 can be used with the primary production from a target field to make a rough prediction of secondary recovery for fields that have been through their cycle of primary production but have not yet been subjected to any type of secondary recovery. As the secondary production at the Dover 36 and Dover 35 fields matures, these fields can be added to the benchmarks and will help to further refine estimates of expected recovery from these fields. Twenty-five pinnacle reefs were reviewed as secondary CO₂ injection candidates and have been assigned grades ranging from “A” (excellent) to “F” (very poor).

Lessons Learned

We have learned that in Niagaran reef reservoirs with multiple wellbores that low volume producing wells do not need to be shut in when CO₂ injection begins in the injection wells. That is, low volume or stripper producing wells can remain producing unless instantaneous break through of CO₂ occurs. This field practice benefits the Operator by providing continued oil sales and income during the reservoir fill up period and also provides an observation well. This practice was followed at Dover 35 and the daily production volumes and static bottom hole buildup tests have provided insights regarding the progress of the CO₂ demonstration project (Figures 5, 6 and 7).

We have also learned in the Dover 35 Field that it may be a good practice to inject CO₂ structurally high in these reef reservoirs and produce from a structurally low position. This practice is similar to the flood configuration used in the nearby Dover 33 field (minus the horizontal and highly deviated wells) but very different than the flood configuration used in the nearby Dover 36 field (central producer and low CO₂ injection wells) operated by industry between 1996 and present day (see details regarding the performance of these fields in the Discussion and Results section).

We have learned that the installation of a sliding sleeve in CO₂ injection wells is a mechanically sound practice in these types of wellbores and reservoirs. In the 1-35 well this mechanical configuration will allow our industry partner to employ a CO₂ huff-n-puff methodology. That is, CO₂ can be injected into the structurally high A1 Carbonate, injection can be halted, the sliding sleeve can then be closed off over the A1 Carbonate thereby opening the Brown Niagaran, and the well can be allowed to flow or placed on pump to produce oil. Alternately, the Brown Niagaran could be injected with CO₂. The Operator may then repeat the process multiple times or huff-n-puff the reservoir. Our industry partner experimented with the huff-n-puff process in an attempt to develop a best practice for CO₂ floods in these reef reservoirs.

Another observation is that highly deviated well bores may be the best solution for contacting the maximum amount of reservoir given the high lateral and vertical heterogeneities in these Niagaran reef reservoirs. In fact, highly deviated wells may be more preferable than horizontal wells in these types of reservoirs.

Additional lessons learned and reported on earlier are that there is no substitute for capturing the various types of Niagaran reef reservoir data and performing rigorous analysis and reservoir visualization. 3D visualization and well log tomography of the core permeability, core porosity, and gamma ray log data have revealed new observations about the distribution of important reservoir reef properties that impact producibility and economics for enhanced oil recovery and gas storage practices in these reservoirs.

We have also learned early in the demonstration project that flexibility and communication must be maintained by all parties to optimize the timelines for flooding the best and most accessible reefs first (e.g., changing of demonstration project to Dover 35 from Charlton 6) to insure optimum economics and recovery. We also learned that negotiations for a CO₂ supply contract using

waste gas from Antrim processing facilities can become very involved from a legal and contract perspective and take longer than expected.

Applications

The sliding sleeve downhole mechanical configuration for injection wells will likely be used by our industry partners in nearby Niagaran reef fields where enhanced recovery projects using recycled CO₂ are planned for the near future.

Early successful results from the Dover 35 field demonstration suggest that reefs with porosity zones in the A1 Carbonate may be the best targets for CO₂ enhanced oil recovery (i.e., structurally and stratigraphically high zones for injection). That is, a new selection criteria for screening existing reef reservoirs to select the best candidates for detailed studies for CO₂ projects has likely been established. In addition, the Dover 35 demonstration project results to date and the Dover 33 and 36 producer/injection well configurations have established an additional new best practice to inject high and produce low using two or more producing wells. Also, highly deviated wells may be better for contacting maximum reservoir volume than vertical or horizontal wells in these highly heterogeneous reservoirs.

Well log tomography is showing that the reservoir properties of the Niagaran reefs in the Michigan Basin vary both horizontally and vertically. These variations in reservoir rock permeability, porosity, and connectivity must be considered to insure that enhanced recovery operations including CO₂ injection, horizontal well placement, and gas storage facilities are designed appropriately. It appears likely that previous interpretations of reservoir and production engineering data, suggesting that many Niagaran reefs deplete uniformly, are incorrect.

Reefs in the Devonian Traverse Group in the Michigan Basin and in many stratigraphic intervals in other U.S. basins are logical targets for application of 3D visualization, well log tomography, highly deviated wellbores and sliding sleeves to assist in the determination of the viability of secondary or tertiary recovery projects and CO₂ sequestration. Our demonstration project results and reservoir studies in combination with the technical literature on world-wide reefs suggest that most reef reservoirs may have undrained reservoir compartments.

Future Work

Future work includes additional pressure buildup measurements in the 1-35 (injector), 4-35A (injector/producer) and in the 5-35 (producer) as deemed prudent by our industry partners. Surface facility configurations will be adjusted to improve production. In addition, a test will be made of the producing potential of the Brown Niagaran (huff-n-puff production technique) using the sliding sleeve mechanical configuration in the 1-35 well. As the project progressed the operator decided to drill a new producing well in the reef (highly deviated) to access the base of the oil column in the reef and undrained reservoir compartments. This well was an extension of the Pomerzynski 5-35, a flank well in the Dover 35 reef, which presently has one well used for CO₂ injection (Salling-Hansen 1-35) and two producers (Salling-Hansen 4-35A and Pomerzynski 5-35). In the late fall of 2005, plans were made to kick the 5-35 to a bottom hole location that was higher on the reef in an attempt to encounter a greater pay section which it was hoped would

improve the level of field production. A permit for redrill was acquired, plans were made to plug back the 5-35 and a rig was scheduled for the redrill. On January 13, 2006 a completion rig moved on location to plug back the 5-35 and set a kick-off-plug to be used to redrill the well. After the bottom hole plugs were placed and while attempting to freepoint the 5 1/2" casing we realized there was a problem. A cement bond log was run on the upper portion of the hole which showed the casing to be bonded from approx 850' to 1500'. This was likely a repair for a previous well-bore problem though it does not show up in any of our records or those with the DEQ. After looking at possible options, we decided the best one was to return the Pomerzynski 5-35 to production and consider an additional well or redrill at a later time.

The 3D visualization and well log tomography techniques applied to our type-reef fields will be applied to the Dover 35 reef and vicinity during the future project periods. Well, field, and reservoir data will continue to be gathered for other Niagaran reefs in the Michigan Basin to identify likely candidates and screening criteria for future CO₂ injection and sequestration projects in these Niagaran reefs.

Core Energy plans to continue to investigate the usefulness of the 3D seismic data in the Dover 35 field and vicinity. One of their contractors used the seismic data to plan a new sidetrack for better injection. Unfortunately this particular project ended in failure, but Core Energy will continue to use the seismic data as the field flood develops.

Finally, we plan to monitor the secondary recovery operation at the project demonstration well, the Dover 35, as well as the Dover 36, to develop better predictors of ultimate recovery from the pinnacle reef fields. In the next decade, say 2006 - 2016, we anticipate that there will be increasing interest in the old pinnacle reef trend, particularly since there is at present, a convenient supply of CO₂ from the Antrim shallow gas operations.

Technology Transfer

We have been in contact with our industry partners on a regular basis during this project to discuss and communicate reservoir architecture modeling results and observations and to discuss the ongoing injection progress, production results, pressure buildup tests, well bore mechanical configurations, surface facility modifications and regulatory issues.

A technical paper was published in the Bulletin of the American Association of Petroleum Geologists in April 2005 entitled, "Well Log Tomography and 3D-Imaging of Core and Log Curve Amplitudes in a Niagaran Reef, Belle River Mills Field, St. Clair County, Michigan, U.S." To view the full well log tomography and 3D animations for the Belle River Mills and/or Chester 18 fields described in this article, readers may access the AAPG website, www.aapg.org/datashare/index.html and select *Datashare 18*.

The annual planning meeting with our industry partners was held in Tampa, Florida along with a carbonate field trip with students, Western Michigan University faculty, and our industry partners in the Bahamas during the week of March 4-11, 2005. An article was published in the June 25, 2005 issue of the Oil & Gas Journal highlighting our work with the historical production data in Michigan.

An article was published in the February 9, 2004 issue of the Oil and Gas Journal that highlighted our regional sample attribute mapping and fault delineation work. The annual planning meeting with our industry partners was held in Tampa, FL in early March 2004. Regional maps were posted for viewing by operators from the basin at the PTTC core workshop on March 19, 2004 in Mt. Pleasant, MI. Regional maps were also posted in a booth at the Michigan Oil and Gas Association's Annual Oil Conference on April 22, 2004 in Gaylord, MI and an oral presentation was made highlighting opportunities for exploration in the Michigan Basin. We participated at the Michigan Basin Geological Society Annual Field Excursion from April 30 to May 2 with a presentation on our basin-scale well log tomography and by attending several of the field stops in the Traverse and Dundee carbonates. Presentations were also made at the monthly northern Society of Petroleum Engineers meeting in May, 2004, the monthly Michigan Basin Geological Society meeting in May, 2004, the Michigan Basin USGS Assessment PTTC workshop in September 2004, and the Eastern AAPG Meeting in Columbus, Ohio in October 2004. A field trip was also conducted in September 2004 for the Depositional Environments class (10 students) that visited various Michigan Basin outcrops, attended the Michigan Basin Assessment PTTC workshop, and participated in core description and interpretation exercises at the Michigan Basin Core Analysis Laboratory at Western Michigan University.

Results and presentations from a portion of this technology transfer are available on the internet at <http://www.geo.mtu.edu/~aswylie/indxhtml.htm> and on our main subsurface visualization web page <http://www.geo.mtu.edu/svl/>.

2.0 EXPERIMENTAL

2.1 Well Details - Dover 35 Field

The Dover 35 field is comprised of three active wells and one abandoned producer (Figure 4). Two of the active wells, the 4-35A and the 1-35 were converted to CO₂ injection wells in 2004. In May of 2005, the 4-35A was reconfigured so that it could be either a producing well or an injector well. It has been more successful as a producer than an injector from May through December of 2005. The 5-35 also remains as an active producer in the field demonstration project.

Log curve abbreviations used in subsequent figures include - GR (gamma ray, api units), CALI (caliper, inches), RHOB (bulk density, gr/cm³), DT or BCDT (bore hole compensated sonic log, transit time, ft/sec), PEF (photoelectric factor, barnes/electron), DIFF_GR (gamma ray difference curve, api units), LLD (laterolog deep, ohm-m), LLS (laterolog shallow, ohm-m), MML (micro-laterolog, ohm-m), MSFL (micro-spherically focused log, ohm-m).

2.1.1 Salling Hansen 4-35A

Overview & Well Background

Shell Oil drilled the Salling Hansen 4-35 vertical well (permit number 29947) in October 1974 but did not encounter the Brown Niagaran at total measured depth of 5564 ft. A whipstock was set at 3475 ft and the well was sidetracked to the southeast. The deviated wellbore, the Salling Hansen 4-35A (permit number 29995) encountered the Brown Niagaran 5428 ft measured depth and 5334 ft true vertical depth.

Location

The well bottom is located 505 ft south and 241 ft east of the surface location based upon the record of the directional survey; bottom hole closure is 559 ft and the drift angle for the deviated well bore ranged up to 21 degrees. The surface location for the 4-35A is 1284 ft from the north and 698 ft from the west line of the northwest quarter of section 35, township 31 north, range 2 west, Dover Township, Otsego County, Michigan (SE/4 NW/4 NW4, section 35, T31N, R2W). The bottom hole location is 851 ft from the south and 939 ft from the west line of section 35 (NE/4 SW/4 NW/4, section 35, T31N, R2W). Ground elevation for the well is 1099 ft above sea level and kelly bushing is 1114 ft.

Drilling and Casing history

The 4-35A encountered the A2 Carbonate at 4238 ft measured depth, the A2 Evaporite at 5336 ft measured depth, the A1 Carbonate (also known as the Ruff Formation) at 5362 ft and the Brown Niagaran (also known as the Guelph Formation) at 5426 ft (Figure 8). The well reportedly reached total depth of 5715 ft on November 21, 1974.

The well was originally cased with 16 inch casing set to 93 ft, 11 3/4 inch casing set to 812 ft, 8 5/8 casing set to 3474 ft and a 5 1/2 inch liner from 3263 ft to 5715 ft (Figure 9).

Open hole testing, coring, mudlogging, and logging

No drill stem testing was conducted in this well and a mudlog could not be located although sample descriptions are provided for the A2 carbonate through total depth (Brown Niagaran) in the State records for the well. A borehole compensated sonic log was run in the original vertical hole on October 18, 1974. Dual laterolog, microlaterolog, and sidewall neutron porosity logs were recorded in the deviated well bore (Figure 8).

According to the sample description report and the well logs, the A1 Carbonate contains approximately a 24 ft thick dolomite zone with neutron porosity as high as 10%; this dolomite zone was described in the cuttings description as tan to dark brown, fine crystalline, sucrosic porosity, gold to white fluorescence and yellow cut.

Sample descriptions through the Brown Niagaran show limestone to be the principle lithology. The main hydrocarbon show was recorded from 5484 to 5560 ft. The limestone was described as dark brown to tan, hard, dense, vuggy to intercrystalline porosity, abundant rhombohedral crystals, some anhydrite, trace of brown and black oil stain, some blue-white fluorescence and fine streaming cut. Neutron porosity through this interval is about 2% on average. Traces of dead oil stain were recorded between 5560 and 5715 ft total depth.

Original Completion

The 4-35A was perforated from 5491 to 5570 ft measured depth with six holes and then acidized with 1800 gallons of 28% HCL (Figure 8 and 9). The well initial potentialed flowing 312 BOPD and 240 MCFGPD on December 21, 1974 with 200 psig tubing pressure. The well produced approximately 142 MBO and 222 MMCF gas through December 2003.

Workover for CO₂ Injection

In order to prepare the 4-35A for CO₂ injection it was necessary to run a tie-back liner to surface from the top of the existing 5 1/2 inch casing during April 2004. CO₂ injection commenced on May 6, 2004, and through December 31, 2004, approximately 300 MM cubic feet was injected (Figure 10). An additional 130 MMCF of CO₂ was injected from February through April of 2005.

A new downhole configuration for the 4-35A was completed on May 26, 2005. The new configuration includes two packers and a sliding sleeve and can produce or inject into either A1-Carbonate or Brown Niagaran similar to the 1-35. The 4-35A was put on production for 6 weeks starting May 27, 2005, and produced 925 barrels of oil, and then was put back on CO₂ injection on July 9, 2005 for 4 days. It has been a producing well since then except for a 9-day period in August, 2005 where it was once again set to CO₂ injection. The 4-35A has currently produced 5420 barrels of secondary recovery oil as of December 31, 2006.

2.1.2 Salling Hansen 1-35

Overview & Well Background

Shell Oil drilled the Salling Hansen 1-35 vertical well (permit number 29236) in May 1973 and encountered the Brown Niagaran at total measured depth of 5359 ft. The Gray Niagaran was encountered at 5730 ft. The Salling Hansen 1-35 was the discovery well of the Dover 35-31N-2W Field.

Location

The surface location for the 1-35 is 990 ft from the south and 797 ft from the east line of the north-west quarter of section 35, township 31 north, range 2 west, Dover Township, Otsego County, Michigan (NW/4 SE/4 NW4, section 35, T31N, R2W). Ground elevation for the well is 1109 ft above sea level and kelly bushing is 1124 ft.

Drilling and Casing history

The 1-35 encountered the A2 Carbonate at 5173 ft measured depth, the A2 Evaporite at 5274 ft measured depth, the A1 Carbonate (also known as the Ruff Formation) at 5298 ft and the Brown Niagaran (also known as the Guelph Formation) at 5359 ft (Figure 11). The well reportedly reached total depth of 5780 ft on May 25, 1973.

The well was originally cased with 16 inch casing set to 117 ft, 11 3/4 inch casing set to 872 ft, 8 5/8 casing set to 3514 ft and a 5 1/2 inch liner from 3257 ft to 5770 ft (Figure 12).

Open hole testing, coring, mudlogging, and logging

Drill stem testing was not conducted in this well and a mudlog could not be located although sample descriptions are provided for the A2 carbonate through total depth (Gray Niagaran) in the State records for the well. A borehole compensated sonic log was run in the well on May 24, 1973. Dual laterolog, microlaterolog, and sidewall neutron porosity logs were also recorded in the well bore (Figure 11).

According to the sample description report and the well logs, the A1 Carbonate contains approximately 30 ft of dolomite with neutron porosity as high as 14% (5318-5340 ft); this dolomite zone was described in the cuttings description as dark brown, fine crystalline, with intercrystalline porosity and some vugs, bright yellow fluorescence and no cut.

Sample descriptions through the Brown Niagaran show limestone to be the principle lithology with one dolomite zone from 5640-5670 ft. The main hydrocarbon shows were recorded from 5346 to 5540 ft. The limestone was described as tan, brown and dark grey, fine to medium crystalline, crystals on edge of cuttings (could be rhombohedral calcite or dolomite?), bright yellow fluorescence, trace cut with fair cut when crushed.

Original Completion

The 1-35 was perforated at 5475, 5480, 5492, 5500, 5510, 5516 ft measured depth with six holes and then acidized with 3500 gallons of 28% HCL (Figure 11 and 12). The well initial potentialized flowing 384 BOPD and 172 MCFGPD on June 3, 1973 with 549 psig tubing pressure. Oil gravity was 42.3 and gas-oil ratio 449/1. Initial choke size was 15/64th. The well produced approximately 710 MBO and 549MMCF gas through December 2003.

Workover for CO₂ Injection

The 1-35 was taken off production in the second quarter of 2004 and converted to a CO₂ injection well. A tie-back liner was run in the well. A sliding sleeve downhole assembly was installed in the wellbore so either set of perfs, A1 Carbonate or Brown Niagaran, could be used for injection (refer to Figures 11 and 12). The sliding sleeve assembly will also allow the well to be operated as a huff-n-puff well (injection into upper perfs and production from lower perfs). The well has performed very well under injection and had cumulative injection of 1770 MMCF of CO₂ through December 31, 2005 (Figure 13).

2.1.3 Pomerzynski 5-35

Overview & Well Background

Shell Oil drilled the Pomerzynski 5-35 vertical well (permit number 37324) in December 1983 and encountered the Brown Niagaran at total measured depth of approximately 5603 ft. It is postulated that the Pomerzynski 5-35 was drilled to locate bypassed oil in the Dover 35 Field.

Location

The surface location for the 5-35 is 330 ft from the north and 1021 ft from the east line of the northwest quarter of section 35, township 31 north, range 2 west, Dover Township, Otsego County, Michigan (NW/4, NE/4, SW4, section 35, T31N, R2W). Ground elevation for the well is 1129 ft above sea level and kelly bushing is 1140 ft.

Drilling and Casing history

The 5-35 encountered the A2 Carbonate at 5254 ft measured depth, the A2 Evaporite at 5351 ft measured depth, the A1 Carbonate (also known as the Ruff Formation) at 5574 ft and the Brown Niagaran (also known as the Guelph Formation) at 5603 ft (Figure 14). The well reportedly reached total depth of 5715 ft (measured depth driller) or 5668 ft (measured depth logger) on December 20, 1983.

The well was originally cased with 16 inch casing set to 80 ft, 11 3/4 inch casing set to 753 ft, 8 5/8 casing set to 3082 ft (possibly 3583 ft) and a 5 1/2 inch liner from approximately 3200 ft to 5715 ft (Figure 15).

Open hole testing, coring, mudlogging, and logging

Drill stem testing was not conducted in this well and a mudlog could not be located. No detailed report of lithology and show information in the well could be located. A lithodensity-compensated neutron log was run in the well on December 20, 1983. A dual laterolog and a microlaterolog were also recorded in the well bore (Figure 14).

Original Completion

The 5-35 was perforated from 5514-4419, 5524-5535, and 5575-5588 ft measured depth and then acidized with 5000 gallons of 28% HCL (Figure 14 and 15). The well initial potentialized pumping 85 BOPD and 85 MCFGPD on January 20, 1984. Oil gravity was 40.7. The well produced approximately 68 MBO and 44 MMCF gas through December 2003.

Workovers for Production

The 5-35 was producing approximately 9 BOPD from the start of injection into the 4-35A in May 2004 until two weeks after the start of injection into the 1-35 when production increased to approximately 90 BOPD. The well was pumping 100% of the time and trying to flow. Our industry partners elected to pull the pump and rods out of the well in October 2004 and attempted to swab the well in; three bottom hole pressure buildup tests were also conducted during this time. Finally, in November 2004 the well began to flow at daily rates up to 300 BOPD (Figure 16).

However, the 5-35 was still experiencing two mechanical problems in early December 2004. One problem had to do with the surface processing facilities and flow lines and their capacities and these issues were resolved in early January 2005. A new three inch flow line was laid from the well to the surface facilities and a dedicated high pressure separator was installed. The second problem was the position of the base of the production tubing in the well relative to the perforations (Figure 15). The perforations were 150 ft above the base of tubing which was resulting in the well loading up and killing itself. This configuration was appropriate for the well when it was pumping, but now that the well was flowing, the bottom of the tubing needed to be above the perforations. Our industry partner brought in a work over rig to pull the tubing in mid-January 2005 and the downhole mechanical configuration was modified to handle the flowing conditions. The well appears to be stabilizing and is flowing an average 31 BOPD (July-December, 2005).

2.1.4 Pomerzynski 2-35

Overview & Well Background

Shell Oil drilled the Pomerzynski 2-35 vertical well (permit number 29374) in September 1973 and encountered the Brown Niagaran at total measured depth of approximately 5470 ft. The Gray Niagaran was encountered at 5685 ft.

Location

The surface location for the 2-35 is 508 ft from the north and 800 ft from the west line of the northwest quarter of section 35, township 31 north, range 2 west, Dover Township, Otsego County, Michigan (NE/4, NW/4, SW4, section 35, T31N, R2W). Ground elevation for the well is 1128 ft above sea level and kelly bushing is 1140 ft.

Drilling and Casing history

The 2-35 encountered the A2 Carbonate at 5227 ft measured depth, the A2 Evaporite at 5320 ft measured depth, the A1 Carbonate (also known as the Ruff Formation) at 5359 ft and the Brown Niagaran (also known as the Guelph Formation) at 5470 ft (Figure 17). The well reportedly reached total depth of 5760 ft (measured depth driller) on December 25, 1973.

The well was originally cased with 16 inch casing set to 66 ft, 11 3/4 inch casing set to 755 ft, 8 5/8 casing set to 3560 ft and a 5 1/2 inch liner from approximately 3200 ft to 5760 ft.

Open hole testing, coring, mudlogging, and logging

Drill stem testing was not conducted in this well and a mudlog could not be located although sample descriptions are available for the A2 carbonate through total depth (Gray Niagaran) in the State records for the well. A borehole compensated sonic log was run in the well on September 25, 1973. Dual laterolog, microlaterolog, and sidewall neutron porosity logs were also recorded in the well bore (Figure 17).

According to the sample description report and the well logs, the A1 Carbonate contains approximately 65 ft of dolomite with neutron porosity of 2% (5360-5425 ft); this dolomite zone was described in the cuttings description as buff, finely sucrosic and vuggy porosity, fair stain, no fluorescence, finely crystalline and argillaceous.

Sample descriptions through the Brown Niagaran show limestone to be the principle lithology. The main hydrocarbon shows were recorded from 5440 to 5530 ft. The limestone through this interval was described as buff to white, trace dolomite, slightly sucrosic to finely crystalline, argillaceous, fair porosity, good bright yellow fluorescence, no cut and dead oil stain. Only trace to poor fluorescence was described in the lower Brown Niagaran.

Original Completion

The 2-35 was perforated from 5450-5540 ft measured depth with 16 holes and then acidized with 1350 gallons of 15% HCl; the well was acidized again with 3000 gallons of 28% HCl. The well initial potentialized flowing 300 BOPD and 204 MCFGPD on October 22, 1973. Tubing pressure was 290 psig. The well produced approximately 32 MBO and 20 MMCF gas through Oct. 1987.

Abandonment

The 2-35 well was permanently abandoned on October 14, 1987 probably due to poor performance.

2.2 Log Data

2.2.1 Log Data Capture

Paper copies of the well logs for the Dover 35, Charlton 6, Belle River Mills and Chester 18 Fields and surrounding area were obtained from the files at Michigan Tech and scanned to create tagged image format (tif) digital images using the commercial Neuralog software and a 36-inch scanner. Neuralog software was used to digitize the gamma ray and/or transit time (sonic), bulk density, neutron, and resistivity log curves for each well; the resistivity curves were not captured for Belle River Mills due to their vintage and low vertical resolution. Log ASCII Standard 2.0 (LAS) files were output from the Neuralog software to use in subsurface interpretations, log curve amplitude slicing and cross sections.

2.3 Production Data Capture

Digital monthly production data records from January 1982 through June 2003 were obtained from the Michigan Department of Natural Resources in a series of MS Access data files and then recombined into one composite MS Access database. This database contains field names and monthly oil, gas, natural gas liquids, and water production volumes among other data elements. These data can be used to create monthly decline plots for wells, production units, and fields. If the field went on line post January 1982 these data can be summed to determine cumulative production for the field for the period January 1982 through June 2003.

Historical monthly production records prior to January 1982 are not available in digital format from the State of Michigan at this time. Therefore, hardcopy annual reports from 1932 through 1984 were obtained with annual production data and entered into our digital production database. This enabled us to create historical decline plots for Niagaran fields to use to analyze the performance of individual wells and groups of reservoirs (see Discussion and Results section).

2.4 Data Processing for 3D Visualization

Rockware's Rockworks2002™ suite of software (version 3.5.23) that is capable of excellent 3D manipulation, visualization, and animations was used for 3D-imaging. The key step with the software is the data preparation or data processing to place the various types of data (i.e., logs, tops, locations, etc.) into the required formats for loading into the program. An in house routine has been developed whereby the well and log data is first manipulated in an SQL database and then used to populate the 3D program's spreadsheet loader; however, when file length exceeds spreadsheet limits a series of ASCII text files must be used to load the data into the program. Drawbacks to the program are that all data must be reloaded each time new data is added to a project and the 3D visualization module of the program performs slowly when 0.3 m (1 ft) sample increment log data is loaded for an entire project; a subset must be used to decrease processing and redraw times.

2.5 Well Log Tomography

Well log tomography also known as log curve amplitude slicing (Wylie and Wood, 2005; Wylie and Huntoon, 2003; Wylie, 2002) is a form of tomography that utilizes the full vertical resolution of geophysical well log curves. Amplitude slices represent *approximate* time lines when the interval under analysis is bounded by unconformities or other chronostratigraphic surfaces and show the inferred distribution of lithofacies at the time of deposition. Computer animation allows visualization of changes in the distribution of lithofacies between successive slices or timelines. The distribution of other reservoir properties including porosity, permeability, and water saturation can also be visualized using the technique. The software used to create the tomographic animations includes MS Access, Golden Software Surfer, JASC Paintshop Pro Animator, and an in-house Visual Basic program.

In the case of the Niagaran reefs, only one chronostratigraphic surface is used. The base of the reef (or estimated base of the reef) in each well penetrating a reef is being used to establish one approximate time surface. Bottom-up slicing is then applied utilizing both reef and/or non-reef well penetrations to visualize the distribution of any particular log curve amplitude or other regularly sampled (in depth) reservoir property such as core permeability or core porosity measurements.

2.6 3D Seismic Data

One of our industry partners, Core Energy, LLC., has provided us with a 3D seismic data volume over the Dover 35 Field and vicinity that was acquired by a previous owner of the Dover 35 field in about 1996 (Figure 18). The data arrived on 8 millimeter tapes and was copied to our archive disk space. Accompanying trajectory and spatial information was used to load the data into our LandMark SeisVision PC software for interpretation and analysis.

2.7 Difference Log

We have developed a new technique to visualize the stratal units and surfaces in carbonate rocks. This technique uses the difference between successive log amplitude samples to create a difference curve as a proxy for the rate of change seen in well log curve amplitudes. Examples of the gamma ray difference curve are shown on the well logs in Track 2 (DIFF_GR curve) in Figures 8, 11, 14, and 17 and in the cross section in Figure 19. By plotting the difference in amplitude between successive gamma ray amplitudes (1 ft sample increment) using a 'block' curve presentation and then expanding the scale to maximize the visualization of the difference, new observations are being made about cyclicity, vertical heterogeneity, and subtle stratal units in these reef carbonate rocks. The difference log presentation for the gamma ray and other well log curves may have important implications for correlating stratigraphic sequences, inferring chronostratigraphic surfaces and modeling reservoir properties in all types of carbonate and siliciclastic rocks.

3.0 RESULTS AND DISCUSSION

3.1 Dover 35, 33 and 36 - Field Characteristics and Performance Comparisons

The location of the Dover 35, 33 and 36 Fields in relation to each other is shown in Figures 1b and 3. Figure 20 shows the reservoir characteristics for each field for comparison purposes. One point of interest is the Lithology for the three fields through the A1 Carbonate and Brown Niagaran zones. The A1 Carbonate porosity zone, where present, is normally 100% Dolomite. However, careful review of the Michigan Department of Natural Resources sample description information through the Brown Niagaran in each of the wells in the fields shows this interval in the Dover 35 and 36 fields to be composed of almost 100% Limestone while in the Dover 33 field the Brown Niagaran interval is composed of 100% Dolomite. However, comparison of other reservoir characteristics shown in Figure 20 reveals no other remarkable differences between the fields.

Historical and predicted primary and enhanced oil recovery performance for Dover 35, 33 and 36 is shown in Figure 21. Although, the reservoir characteristics of the three fields are similar the Dover 33 and 36 fields performed very differently under CO₂ flood. Approximately 20.5 BCF of CO₂ had been injected into the Dover 33 field by December 31, 2003 (Figure 22) resulting in 480,000 barrels of tertiary oil recovery by December 31, 2005. CO₂ injection at Dover 33 apparently ceased in December 2003. In contrast, approximately 6.3 BCF of CO₂ has been injected into Dover 36 field through January 26, 2005 (Figure 23) resulting in 257,000 barrels of tertiary oil recovery by December 31, 2005. CO₂ injection pressures were approximately double for the Dover 36 field versus the Dover 33 field. Based upon our studies and our industry partner's experience, we believe the tertiary recovery performance differences are due to reservoir heterogeneity and where the zones of reservoir heterogeneity were penetrated by the injection and production wells. This depends on the position of vertical, horizontal or highly deviated wells relative to the crest or base of reefs.

3.2 Dover 35 Field

CO₂ injection into the 4-35A and 1-35 wells in the uppermost portion of the Niagaran reservoir (A1 Carbonate) in the Dover 35 Demonstration project has resulted in an oil production response in the producing well, the Pomerzynski 5-35. Production has increased from 9 BOPD to a fairly stabilized rate of 52 BOPD (refer to Figures 5, 6 and 7). This is a very favorable early result for the demonstration project considering the downhole and facility mechanical issues that our industry partners have experienced and continue to mitigate in order to improve production and injection performance.

Injection rates for the 4-35A have been lower than expected (approximately 1.3 MMCF per day actual versus 5 MMCF per day expected). We believe the lower injectivity in the 4-35A is likely due to a disconnect of the A1 Carbonate zone in this well with the A1 Carbonate zone in the 1-35 and 5-35 wells (refer to cross section, Figure 19). In other words, these apparently similar appearing zones on the well log correlations are actually two separate porosity zones that may not be in connection with each other and in the case of the 4-35A, may not be in connection with the under-

lying Brown Niagaran. This disconnect interpretation can be supported, in part, by the divergence and different slopes of the static bottom hole pressure measurements shown in Figure 7. It is also likely that the production response in the 5-35 that occurred soon after injection began into the 1-35 indicates early CO₂ breakthrough via the A1 Carbonate. Furthermore, the bottom hole pressure measurements from the Brown Niagaran seem to indicate that the CO₂ being injected into the A1 Carbonate is finding its way into the Brown Niagaran, albeit at a slower rate and likely more tortuous route, than in the A1 Carbonate. We were unable to determine the relative contribution of the 4-35A and the 1-35 to the overall reservoir pressure increase in the Brown Niagaran 5-35 producing well measured by the bottom hole pressure trends (Figure 7). What is known is that the 1-35 is taking at least twice the volume of CO₂ that the 4-35A is taking.

Consideration has been given to adding additional perforations at lower positions in the reservoir to improve injectivity. However, at this time, our industry partners continue to prefer not to perforate either the 4-35A or the 1-35 injection wells deeper in the reservoir because of potential productivity losses related to gravity drainage. Dover 35 recovered approximately 966,000 barrels of oil from primary production, 39,000 barrels of oil from secondary production through 2005, and we estimate between 235,000 and 585,000 barrels of additional oil will be recovered as a result of the CO₂ flood demonstration project.

Reservoir characterization of the Dover 35 Field is complete as far as this project is concerned. However, the CO₂ injection will continue for several more years and production will continue indefinitely. Thus, there is at least another decade of data to be obtained from Dover 35. Well logs in the field and vicinity have been digitized and historical production data has been gathered from the Michigan Department of Environmental Quality hard copy records. Figure 19 shows a structural cross section through the 4 wells in the field with the A2 Carbonate, A1 Carbonate, Brown Niagaran, and Gray Niagaran correlations. The 4-35A was configured as a producer at the end of 2005, but can also be configured as a CO₂ injector. The 1-35 well is being used as a CO₂ injector and the 5-35 well is a producer in the demonstration project. The cross section shows the original perforated intervals and in combination with the wellbore diagrams (refer to Figures 9, 12 and 15) depicts the current downhole mechanical configurations. Variability in the Neutron Porosity, Borehole Compensated Sonic, and Resistivity amplitudes between the four wells (Porosity and Resistivity tracks, Figure 19) indicate significant vertical and lateral heterogeneity exists in the reef carbonates. Well log tomography animations of the neutron porosity and gamma ray amplitudes in the four wells in Dover 35 and the three wells in Dover 36 appear to validate the high lateral and vertical heterogeneity in this single reef reservoir. Figure 24 shows five example bottom up and top down slices of neutron porosity and gamma ray amplitudes through these two reefs.

3.3 Dover 33 Review and Historical Performance

The Dover 33 Field was discovered in 1974 and covers an area of about 100 acres (refer to Figures 1b and 3). Four wells were drilled early in the primary phase of production. In 1996 one of the original producers (Lawnichak Myskier 1-33, permit number 29565) was converted to a CO₂ injection well. The 1-33 well is located in a crestal structural position in the reef. Production was shut in until minimum miscibility pressure was reached in early 1997 about nine months after injection began (Figure 22). Approximately 2.7 BCF of CO₂ was injected to reach minimum miscibility pressure (~1200 psia). Total CO₂ injected/cycled is about 21 BCF through December 2004.

A new vertical well (2-33, permit number 50985) was drilled in the Dover 33 field in November 1996 to a total measured depth of 5774 ft but encountered only 100 ft of dolomite with no shows in the toe of the reef and was abandoned; the other original vertical producing wells were plugged and abandoned prior to conversion for CO₂ flooding. The 2-33 was plugged back and a whipstock was used to drill the well horizontally to the northwest (permit number 51601). 5 1/2 inch casing was set through the turn to 4860 ft measured depth and the well was drilled horizontally 1714 ft to a total measured depth of 6990 ft. The well was completed open hole through the horizontal section. Performance information for this well is unavailable at this time. In late 2003 this well was plugged back and a whipstock was set to redrill the well (2-33HD2) to place the horizontal portion lower in the reservoir just above the interpreted oil-water contact. Unfortunately, the well ran low into the water leg of the reservoir. The horizontal well was plugged back and redrilled again (2-33HD4, permit number 55942) in December 2003 to a slightly higher position in the reservoir. Full performance information for the producing 2-33HD4 is unavailable at this time.

The 5-33HD1 was drilled immediately following the 2-33HD1 in late 1996. The 5-33HD1 (permit number 51603) was drilled at a high angle 1281 ft to the southwest. 5 1/2 inch casing was set to total measured depth of 6456 ft. The well was completed in January 1997 through perforations and tested flowing 224 BOPD of 47.9 gravity and 700 MCF of CO₂.

Due to operational and performance issues related to Dover 33, 35 and 36 our industry partner, Core Energy, LLC, the operator of Dover 33, reduced CO₂ injection into the Dover 33 field in 2004.

3.4 Dover 36 Review and Historical Performance

The Dover 36 Field was discovered in 1973 and covers an area of about 200 acres (refer to Figures 1b and 3). Three wells were drilled early in the primary phase of production. In early 1997 two of the original producers (State Dover Kubacki 1-36 and Kubacki State 3-35, permit numbers 29235 and 29348) were converted to CO₂ injection wells. The Kubacki Cole 2-36 well located in the central area of the reef was planned as the producer for the CO₂ flood. A new vertical well, the Kubacki Cole 3-36 (permit number 52719 and twin to 2-36) was drilled into the reservoir in July 1998 to replace the 2-36 well; the 2-36 was plugged and abandoned. In 1997 the 3-35 was re-

entered and a horizontal leg was added extending approximately 1000 ft to the northeast. Both the vertical and openhole horizontal legs of the wellbore have been used for CO₂ injection.

Production was shut in until minimum miscibility pressure was reached in late 1998 about 29 months after injection began (Figure 23). Approximately 2.1 BCF of CO₂ was injected to reach minimum miscibility pressure (~1200 psia). Total CO₂ injected/cycled is about 5.4 BCF through December 2004.

3.5 Predicted Field Performance - Reefs near Dover 33

3.5.1 Summary: Dover 35

The success of the Dover 35 CO₂ flood can be measured by reference to other CO₂ floods in the region. Of the three previous floods that we are aware of in the vicinity of Dover 35, the Dover 33 CO₂ flood (Figure 25; map of pinnacle reefs around Dover 33) conducted in the period 1997 to 2003 was the most successful, recovering an estimated 480,000+ barrels of oil (as of December 2005) over the original production of 1.29 million barrels (Figure 26), an increase of ~37%. Another CO₂ project, the Dover 36, has produced 257,448 barrels of oil to date and may reach the Dover 33 level over time. Both Dover 33 and Dover 36 can be used to benchmark the demonstration well for this project. However, since the Dover 33 CO₂ flood is the more mature, it is probably better to use just this case for now. (Note that the predicted secondary recovery estimated below uses the present secondary production of Dover 33, not its ultimate estimated production of 750,000 barrels (Figure 21) and hence may be a very conservative estimate.)

If we superimpose the Dover 33 production curve (Figure 27) for both the initial and secondary production onto the original production for the Dover 35 demonstration well (Figure 28) we see that the demonstration well clearly did not have the same initial production as the Dover 33 (960,541 bbls vs 1,287,362 bbls) nor does it show the same peak production, 240,000 bbls/yr for the Dover 33 compared to about 135,000 bbls/yr for the Dover 35. However the two fields have about the same decline tail. If we simply multiply from the initial production ratio ($960,451/1,287,362 = 0.75$) by the actual secondary recovery at Dover 33, we get a crude estimate of a secondary recovery of about 358,248 barrels for Dover 35 (Figure 26). It is also clear from Figure 28 that the demonstration well does not have anywhere near the steep rise in production for secondary CO₂ that Dover 33 had. Dover 33 showed steep increases in production for both initial and secondary recovery and went on to produce 37% more on secondary recovery. The shallower slope for Dover 35 for both initial and secondary recovery suggests that this field will not perform as well as Dover 33, but the next few years will tell.

3.5.2 Comparison of Nearby Fields with Dover 33

We can extend this analysis to nearby fields and estimate probable secondary recovery for them. At present we will benchmark only against the Dover 33 data since it has the more extensive secondary recovery figures. Figures 28 to 36 show comparisons of 27 fields (see Figure 25 for location map) to Dover 33.

(In the following discussion and in Figure 26, the ratings assigned to the various fields are graded from A to F with C being "average" meaning it is expected to perform about the same as Dover 33 on secondary recovery, which is very good from an economic point-of-view. The reason Dover 33 was not assigned "A" is that there are several prospects in the vicinity that grade out even higher (e.g. Charlton 07, Chester 19, etc.). Thus it is important to keep in mind that the ratings only reflect expected performance relative to Dover 33, which is itself a successful secondary flood project.)

Dover 36 (Figure 28) has a production profile nearly identical to Dover 33 and has in fact been placed on secondary CO₂ flood. Thus it also can serve as a benchmark field. It has a good step initial production, basically a single peak and a normal tail. In all respect it would have been predicted, based on the criteria used here, to be about as successful as Dover 33 was on secondary. However that does not appear to be the case based on results to date. While Dover 33 produced over 480,000 bbls on secondary, Dover 36 has only produced 258,000 bbls to date. One significant difference, consistent with the rating criteria used here, is that Dover 36 has a significantly poorer quality tail compared to Dover 33. There are also suggestions of reservoir heterogeneity in the Dover 36 production curve (years 5-10), perhaps compartmentalization. We would have rated this field "C" based on the initial production curve characteristics, and that seems about right. However, it is still on secondary production and may yet approach the production numbers of Dover 33. Estimated secondary recovery: 528,000 barrels. Rating: C

Dover 35 (Figure 28) the demonstration well for this project, shows an inferior initial production curve relative to Dover 33, with a shallow initial production curve but a decline almost identical to Dover 33. However the significantly lower initial production, 960,000 barrels compared to Dover 33's 1,287,000 predicts a lower secondary recovery of 358,000 bbls, which is consistent with results to date. However, since Dover 35 is still under CO₂ flood, the final story has not been told. Estimated secondary recovery: 360,000 barrels. Rating: C-

Dover 12 (Figure 28) looks very much like Dover 35, but with a stronger tail and a better plateau stage. Its IP ratio relative to Dover 33 is 0.76. Estimated secondary recovery: 365,000 barrels. Rating: C-

The **Chester 02** field (Figure 29) we see an initial production (IP) profile similar to the Dover 33, (after a 2-3 year lag). This is followed by two distinct maxima in the production profile, which could reflect field development, but suggests production difficulties possibly related to reef heterogeneity or compartmentalization. This is a may be a telltale signal to look for in these reefs. We would rate the Chester 02 a decent prospect relative to Dover 33; it has decent initial production but the double maximum in the production profile suggests reservoir heterogeneity problems may exist. Rating: C-.

Proceeding to the **Chester 05A** (Figure 29), we see a marginal pinnacle reef field, characterized by low initial recovery (81,369 barrels and a predicted secondary recovery of only 30,351 barrels. Note the two broad production peaks between years 3 and 6. Again the two peaks would suggest redrilling to recover from reservoir heterogeneity except that only 1 well was drilled here. The low reserve number coupled with the hint of compartmentalization lead to a low ranking here. Estimated secondary recovery: 30,051 Rating: D.

Chester 06 (Figure 29) is more encouraging. It shows a steep initial production followed by a plateau then a fairly steep decline and virtually no production tail. This field is significantly unlike the Dover 33 (superimposed dashed curve) even though it had about 92% of the Dover 33 total production. The initial production ratio (Chester 06/Dover 33) is close to 0.95 and the production curve does not show a pronounced double maximum, suggesting that the engineers either did not encounter heterogeneity problems or solved by drilling 3 wells here. Estimated secondary recovery: 456,000 barrels. Rating: C-

Chester 10 (Figure 30) has about the same slope on the initial production curve as Dover 33, and a similar production profile: sharp initial rise, plateau, normal decline. This production profile suggests that heterogeneity problems are minimal. Estimated secondary recovery: 186,000 barrels. Rating: C-

Chester 10A (Figure 30) looks like a very decent prospect. It is close to being a Dover 33 look-alike, and has a 0.98 initial production ratio. It shows a very sharp rise in initial production, sharper than the Dover 33, with a similar initial recovery and decline curve. The double peak (plateaus?) in the production profile suggests reservoir heterogeneity or dual reservoir compartments. The small maximum in the tail of the production curve suggests further reservoir heterogeneity that the engineers solved by drilling a second well (?) or reworking the wells. A review of the development and workover history of this field would likely be very revealing. Estimated secondary recovery: 470,000 barrels. Rating: C

The **Chester 16** (Figure 30) similarly looks like Dover 33. But while it has very sharp initial production curve and similar production (1,330,970 barrels compared to 1,287,363 for Dover 33), it also has steep decline and no production tail. This reservoir may be fairly homogeneous but with good connectivity which allowed a more complete ultimate recovery or else the 5 wells in the field were well placed. This field may have been depleted to a greater extent than the Dover 33, based on the different behaviors of the production tails. We rate the Chester 16 as a slightly lower prospect than Dover 33 because it looks to have been efficiently produced on initial production and because it has no production tail. However it could be a Dover 33 "look-alike" in terms of secondary recovery if we are wrong in our interpretation of the lack of a production tail. Estimated secondary recovery: less than the calculated 496,000 barrels (Figure 26). Rating: C-

Chester 18 (Figure 31) is another giant pinnacle and excellent prospect for secondary recovery. It has a sharp initial production (data for years 1-2 missing?), excellent initial production ratio and a long decline tail better than Dover 33. It shows a double maximum in the initial production curve (years 1-10), suggesting compartmentalization which the engineers solved. It also suggests the possible existence of compartments. The engineers drilled 26 wells to exploit this field, indicating that a secondary CO₂ flood here will be a large, expensive project. We think it is unlikely that Chester 18 will yield 4,000,000+ indicated in the table in Figure 26 because the initial production curve is so unusual. However it should yield 2,000,000+ barrels on secondary recovery. Estimated secondary recovery: see comments. Rating: A

Chester 19 (Figure 31) looks to be significantly better than Dover 33. It has better initial recovery (2,511,000 barrels compared to 1,287,000). It has a strong mid-production plateau and an encouraging decline tail. The only negative is that it does not have a sharp initial production curve but all

other indicators are positive. It appears that the production was constrained from year 5 through 15. Estimated secondary recovery: 936,614 barrels. Rating: B+

Chester 21 (Figure 31) is in another league. Note the change of vertical scale. It has a production ratio of 6.4 relative to Dover 33 and even in decline out produces Dover 33. It has a very steep initial production to a maximum of 1.3 million bbls/yr, followed by a very curious steep decline to less than 200,000 bbls/yr at year 6. From year six on, it shows a fairly stable production plateau around 200,000 bbls/yr, with 3-4 wells defined maxima. However, at year 21, production appears to have ceased. Nevertheless we rate this as an "A" level prospect based on its initial production strong central plateau. The several production maxima during years 6-20 suggest problems related to reservoir heterogeneity and thus probably reservoir compartmentalization. Note that engineers drilled 6 wells to drain this field and this indicates that a CO₂ flood will have to be carefully designed, particularly since it is likely that some of the existing well will need either extensive workover or redrilling. Estimated secondary recovery: 3,075,000 barrels. Rating: A

The **Charlton 06** (Figure 32) is a significantly lesser prospect than Dover 33. Although it shows a steep initial production curve, it has a peak less than half of Dover 33 and an initial recovery ratio of 0.49. It also has no significant tail. Estimated secondary recovery: 235,000 barrels. Rating: C-

Charlton 07 (Figure 32) is a very good prospect, with sharp initial production, a sustained middle production from year 5 to 15, and a substantial production tail. The middle production plateau shows several (5-6) peaks that could indicate reservoir heterogeneity. The production history records should yield some clues as to whether this is the case. This field has a very favorable initial production ratio of 2.7 relative to Dover 33. Estimated secondary recovery: 1,295,000 barrels. Rating: A

Charlton 19 (Figure 32) shows an initial production profile very similar to the Dover 33, but has a total initial production ratio of 0.76 and has virtually no tail. It shows one isolated secondary production peak between years 7 and 10, which could indicate compartmentalization (2 compartments?). We rate Charlton 19 as a "C" level prospect based on its similarity to Dover 33 (good) but no production tail (bad). With careful handling it and a little luck it could be another Dover 33. Estimated secondary recovery: 366,000 barrels. Rating: C

Charlton 09-30N (Figure 33) is a lesser field with good initial production, followed by a normal decline and a secondary peak that suggests secondary recovery (?) but has only one well. The reservoir may have dual compartments, which could be a plus. However its small size relative to Dover 33 (IP ratio = 0.46) and lack of good production tail causes us to downgrade this prospect. Estimated secondary recovery: 220,000 barrels. Rating: C-

Similarly, the **Charlton 10-30N** (Figure 33) looks similar to the Charlton 09-30N: good initial production, an IP ratio of 0.57 relative to Dover 33 and a suggestion of 1-2 secondary production peaks. It has no significant production tail. Estimated secondary recovery: 272,000 barrels. Rating: C-

The **Charlton 09-31** (Figure 33) has significantly better initial production than Dover 33 (IP ratio = 3.5). It has a broad production plateau with two discernable decline tails, suggesting dual com-

partments (at least). It has a good decline tail significantly better than Dover 33. Estimated secondary recovery: 1,650,000 barrels. Rating: A

The **Charlton 27** (Figure 34) has a superior production profile compared to Dover 33; a steep initial production, moderate plateau, and two-stage decline with a good tail. It has an IP ratio of 1.97 relative to Dover 33. Estimated secondary recovery: 930,000 barrels. Rating: B+

Charlton 28A (Figure 34) is a Dover 33 look-alike, with steeper initial production, slightly better initial recovery (IP ratio = 1.47) and a similar tail. Estimated secondary recovery: 700,000 barrels. Rating: B+

The **Charlton 34** (Figure 34) has a significantly different production profile compared to Dover 33. It has a sustained production plateau with three peaks, suggesting reservoir heterogeneity and/or compartmentalization and what appears to be the beginning of a long decline tail. The IP ratio relative to Dover 33 is 2.4. We rate this prospect as "B+" based on its long production plateau, suggesting that most of the reservoir can be reached, and the production decline tail is not yet established. It is likely that this field can continue to produce quite well (20-30,000 bbls/yr) for another 10-15 years without secondary recovery. Note that it does have its own characteristic production curve, somewhat similar to Chester 19 and Charlton 07 and Charlton 09-31. Estimated secondary recovery: 1,150,000 barrels. Rating: B+

Charlton 30 (Figure 35) is a Dover 33 look-alike with similar steep initial production, an IP ratio = 1.1 relative to Dover 33 and a lightly inferior tail. Estimated secondary recovery: 530,000 barrels. Rating: C

Charlton 31 (Figure 35) has a shallower initial production curve relative to Dover 33 but has a similar production curve with one peak and an inferior tail. Although it has an IP ratio of 0.92 relative to Dover 33, we rate this prospect as "C-" at best and expect it to underperform relative to Dover 33. The inferior production tail is of concern. Estimated secondary recovery: 440,000 barrels. Rating: C

Charlton 33 (Figure 35) is a poor prospect. Comparison of its production curve with Dover 33 shows a smaller peak (100,000 bbls/year compared to 225,000) followed by rapid decline with no tail and a secondary tail at the end (year 16-18) suggesting some secondary production has already been tried. The low IP ratio, = 0.36, relative to Dover 33. Estimated secondary recovery: 170,000 barrels. Rating: D

Dover 22 (Figure 36) ranks as one of the worst prospect in this portfolio, if not the worst. Comparing its production profile to Dover 33 tells the tale: shallow initial production, very small total production (93,051 bbls compared to 1,287,000 for Dover 33), with an IP production ratio of 0.07. Estimated secondary recovery: 34,000 barrels. Rating: D

The **Dover 22A** (Figure 36) is similar to Dover 22: low initial production, IP ratio = 0.08, but a long tail, suggesting some potential for secondary recovery. However there is already a slight peak at year 22 suggesting attempts to boost production were already made on this field. Estimated secondary recovery: 40,000 barrels. Rating: D

Dover 25 (Figure 36) is marginally better than Dover 22 or 22A with steep initial production and a reasonable profile, but significantly scaled down relative to Dover 33. The IP ratio of 0.17 predicts that this field will yield only about 80,000 bbls of oil on secondary. Estimated secondary recovery: 80,000 barrels. Rating: D

3.5.3 Summary of Dover 33 vs. Nearby Oil Fields

The rankings for the 27 fields discussed above are summarized in Figure 26 along with the relevant ranking data and ratios. It is clear that initial production profiles (Figures 28-36) differ considerably for these fields, ranging from the Dover 33 look-alikes (Charlton 19, Dover 36 and Charlton 28A) to low-potential fields (Dover 22 and Dover 22A). In between are fields characterized by steep initial production and long, steady plateaus (Chester 19, Charlton 09-31) and a few off-scale fields (Chester 21 and Chester 18). In spite of these differences, we have attempted to predict the performance of these fields under CO₂ flood using primarily the ratio of initial production of field in question to the initial production of the Dover 33. This ratio, multiplied by the known secondary CO₂ flood recovery of Dover 33, then yields a rough estimate of what might be expected for the field in question. That this is a crude measure is acknowledged, but the basic concept appears sound and can be refined as more data from secondary recoveries, whatever the type, become available. Dover 36 is largely available now, though the flood is not complete, and this demonstration at Dover 35 will be available in a few years. At that time it might be appropriate to redo the predictions. However, we think that this methodology can be recommended in the interim to evaluate the potential for a pinnacle reef field for secondary CO₂ flooding. In as much as there are over 1000 pinnacle reefs in the Northern Michigan Reef Trend, this is a simple way to get a ballpark estimate of ultimate recovery and assign a relative risk factor.

In addition to the primary production ratio, the shape of the initial production curves may serve to further identify a field's potential for secondary recovery and thus reduce risk or set premiums for investment. Also, the number of wells drilled, with the drilling history (dates, notes, locations and depths, etc.) can provide valuable information relevant to secondary recovery efforts. At some point, plotting of field locations coded for secondary recovery success (measured in bbls produced?) might be useful in high-grading prospects since similar production behavior might be expected for reefs built under similar conditions.

Finally, we need to emphasize the likelihood that most, if not all of these pinnacle reefs, are very heterogeneous, and hence likely to be compartmentalized. It is unfortunate that more cores are not available to study this aspect of the problem. (Although the large number of wells drilled at Chester 18 suggests that a log study here might be useful.) To put it simply, we think that there is much to be learned about the genesis and architecture of these fields that would go a long way to helping pinpoint good prospects as well as optimal flooding strategies. It has to be admitted that at the present the state-of-the-art is primitive and unlikely to improve without directly addressing this problem of reservoir architecture.

In this regard, we should also mention that it is currently fashionable to suggest that CO₂ can be sequestered in old fields such as these reefs, a process that would not only remove CO₂ from the atmosphere but would also produce hydrocarbons in the process. While this is basically a good

idea, and feasible in our opinion, we caution that the process is not likely to be as straightforward as originally conceived, primarily due to the difficulty of injecting CO₂ into pinnacle reefs. If there is one lesson learned from the Dover 35 demonstration project, it is that the extreme heterogeneity of the reef prevents a simple one-stage single-point injection of gas. Dover 35 made it clear that not all levels and compartments in the reef can be reached with a single injector at a single point. There is still much to be done as far as optimizing CO₂ floods in pinnacle reefs.

There is currently a project to see if 3D/4D seismic can help by monitoring gas presence and movement, but this is as yet unproved. It is not likely to do away with the need for a few good cores either, since core can be used to calibrate and interpret the seismic.

3.6 Summary

The Dover 33 field has performed well under CO₂ injection recovering 480,000 barrels (1997-2005) of incremental oil, about 37% of the primary production and approximately 10% of the original oil in place (Figures 37 and 38). The primary plus tertiary recovery factor is about 42%. Most of this oil was recovered in the first three years of the project (refer to Figure 22). The field injection/production pattern, one crestal injector (practice being followed for Dover 35) likely resulted in maximizing the gravity aspects of CO₂ miscible flooding. The strategy of placing two horizontal/highly deviated producers through the reservoir likely maximized the reservoir contact area for production. However, it may be possible to improve the tertiary recovery in future CO₂ floods of Niagaran reefs through improved modeling and well placement (more horizontal wells? highly deviated wells? if economically viable) and through injection and/or production and/or facility best practices.

The Dover 36 field has recovered approximately half the incremental oil recovered in the Dover 33 field (Figures 37 and 38). Under CO₂ injection, the Dover 36 field has recovered 257,000 barrels (1999-2005) of incremental oil, about 19% of the primary production and approximately 5% of the estimated original oil in place. The primary plus tertiary recovery factor is about 36%. The oil continues to be recovered at good rates (~80 BOPD) and these rates may continue for several more years (refer to Figures 23, 37 and 38). These longer lived and lower production volumes contrast with the higher initial rates of production measured in the Dover 33 flood. The injection/production pattern for the Dover 36 field, one crestal producer and two flank injectors, is believed to have resulted in the lower incremental recovery to date using CO₂ miscible flooding.

We expect Dover 35 to perform more like Dover 33 (refer to Figures 37 and 38) based upon reservoir characterization and flood and mechanical configurations. We estimate that Dover 35 will recover from 235,000 to 585,000 barrels of oil from CO₂ injection. Dover 35 daily oil production and cumulative CO₂ injection from January 2004 through February 2006 is shown in Figure 39. Dover 35 is in the beginning stage of response from the CO₂ injection.

4.0 CONCLUSION

The injection of CO₂ into the Niagaran reservoir in the Dover 35 field in Otsego County, Michigan began on May 6, 2004 using the Salling-Hansen 4-35A well. In August 2004 the Salling-Hansen 1-35 was converted from a producer to an injector and placed on injection. Approximately 2.18 BCF of CO₂ has been injected into the reservoir using these two wells through December, 2005. Oil production has increased in the Pomerzynski 5-35 from 9 BOPD to an average 61 BOPD (Jan-Dec, 2005) and then leveling to an average 31 BOPD (July-Dec, 2005) as a result of CO₂ injection. The 4-35A well was also reconfigured to allow the operators to use the well as either a producing well or as a CO₂ injection well. Production has averaged at 29 BOPD (May-Dec, 2005)

The CO₂ injection phase is now fully operational and most downhole mechanical issues and surface facility modifications have been completed. It is anticipated that filling operations will now run for another 12-18 months. In most other aspects the demonstration is going well and hydrocarbon production has increased to a relatively stable rate of 57 BOPD down from the previous report primarily due to changing well configurations to inject more CO₂. The expectation is that production will exceed previous levels when the CO₂ is fully injected. Our industry partners continue to experiment with injection rates and pressures and the huff-n-puff technique to develop best practices for these types of enhanced recovery projects.

A twelve month no-cost extension for this project was requested and approved in late 2004 to complete the injection and fully access the operations. This final report compares the performance of this demonstration (Dover 35) with the two previous CO₂ injection programs (Dover 33 and Dover 36) in nearby reefs, and 24 similar pinnacle reef fields in the vicinity of Dover 35. Work will continue on characterization of the Dover reefs and the identification of additional reefs for CO₂ enhanced recovery projects.

Well log tomography and 3D imaging of the core permeability, core porosity and/or gamma ray and porosity curves for the Belle River Mills, Chester 18, and Dover 35 reservoirs is underway or has been completed. Results indicate significant heterogeneity exists in Niagaran reefs that could impact reservoir performance. This heterogeneity should be considered in the planning of primary, secondary, tertiary or gas storage projects in these types of fields. Highly deviated well bores may be the best answer for contacting the greatest amount of the re-energized hydrocarbon column in these highly heterogeneous carbonate reefs.

4.1 Technology Transfer Activities

4.1.1 Presentations

Petroleum Technology Transfer Council, Mt. Pleasant, MI (March 19, 2004) "Imaging of Niagaran Fields Using Well Log Tomography and 3D Visualization", A. Wylie.

Michigan Oil and Gas Association, Gaylord, MI, (April 22, 2004) "Exploitation and Exploration Opportunities in Michigan - New Views of a Mature Basin or Practical Technology combined with Old Fashioned Prospecting", A. Wylie.

Society of Petroleum Engineers, Traverse City, MI (May 16-18, 2004) "Application of Well Log Tomography to the Dundee and Rogers City Limestones, Michigan Basin, USA", J. Wood.

Michigan Basin Geological Society, Traverse City, MI (May 19, 2004) "Alternate Views of Well Logs Using Well Log Tomography", A. Wylie.

Petroleum Technology Transfer Council, Grand Rapids, MI (September 23, 2004) "Views of Existing and Prospective Producing Formations in Michigan", A. Wylie. Included four-day field trip with 10 students, participation by students in PTTC workshop, visits to various outcrops, exercises in core description at the Western Michigan University Michigan Core Repository.

AAPG Eastern Meeting, Columbus, OH (October 3-6, 2004) "Map views of the producing formations in Michigan, the Michigan Basin, U. S.", A. Wylie and J. Wood.

AAPG Eastern Meeting, Columbus, OH (October 3-6, 2004) "Depositional patterns in the Trenton and Black River Formations revealed by well log tomography and K-bentonite time planes, Michigan Basin and beyond", A. Wylie.

AAPG Eastern Meeting, Columbus, OH (October 3-6, 2004) "Application of well log tomography to the Dundee and Rogers City Limestones, Michigan Basin, U. S.", J. Wood.

Presentation to Faculty & Staff at Texas Technological University, Lubbock, Texas (February, 2005), A. Wylie.

4.1.2 Meetings with Jordan Exploration Company, LLC and Core Energy, LLC

February 1-4, 2004, Traverse City, Meeting to discuss Dover 35 project.

March 7-14, 2004, Annual Project Meeting and Field Trip to view carbonate depositional environments in the Florida Keys in conjunction with Western Michigan University and our industry partners; included student participants and presentations.

April 21-23, 2004, Traverse City, Meeting to discuss Dover 35 project.

May 16-18, 2004, Traverse City, Meeting to discuss Dover 35 project.

June 3-8, 2004, Traverse City, Meeting to discuss Dover 35 project.

July 8, 2004, Traverse City, Meeting to discuss Dover 35 project.

September 9-12, 2004, Traverse City, Meeting to discuss Dover 35 project.

November 9-17, 2004, Traverse City, Meeting to discuss Dover 35 project.

March 4-11, 2005, Annual Project Meeting and Field Trip to view carbonate depositional environments in the Bahamas in conjunction with Western Michigan University; included student participants and presentations.

May 15-16, 2005, Traverse City, Meeting to discuss Dover 35 project.

June 16-18, 2005, Traverse City, Meeting to discuss Dover 35 project.

September 7-10, 2005, Traverse City, Meeting to discuss Dover 35 project.

December 12-16, 2005, Traverse City, Meeting to discuss Dover 35 project.

4.1.3 Publications

Wylie, A. S., Jr. and Wood, J. R., 2005, Historical Production trends suggest remaining up-side for exploration and development in Michigan: *Oil & Gas Journal*, v. 103, no. 23, 9 pp.

Wylie, A. S., Jr. and Wood, J. R., 2005, 3D-Imaging of Core and Log Curve Amplitudes in a Niagara Reef, Belle River Mills Field, St. Clair County, Michigan, U.S.: *AAPG Bulletin*, v. 89, no. 4, p. 409-433.

Wood, J. R., Wylie, A. S., Jr., and Quinlan, W., 2004, Surface Geochemical results complement conventional approaches: *World Oil*, v. 225, no. 12, p. 54-57.

Wylie, A. S., Jr. and Wood, J. R., and Harrison, W. B., III, 2004, Michigan Trenton-Black River opportunities identified with sample attribute mapping: *Oil and Gas Journal*, v. 102, no. 6, February 9, 2004, p. 29-35.

5.0 REFERENCES

- Michigan Department of Environmental Quality, 2005, Download Oil and Gas Production History: <http://www.michigan.gov/deq/0,1607,7-135-3311_4111_4231-97834--,00.html> Accessed December 15, 2005.
- Wylie, A. S., Jr., 2002, Log Curve Amplitude Slicing - Visualization of well log amplitudes for paleogeographic reconstruction of the Middle Devonian Traverse Group, Michigan Basin: Ph. D. dissertation, Michigan Technological University, Houghton, MI, 250 p.
- Wylie, A. S., Jr. and Huntoon, J. E., 2003, Log Curve Amplitude Slicing - Visualization of Log Data and Depositional Environments for the Devonian Traverse Group, Michigan Basin, U. S.: AAPG Bulletin, v. 87, no. 4, p. 581-608.
- Wylie, A. S., Jr. and Wood, J. R., 2005, 3D-Imaging of Core and Log Curve Amplitudes in a Niagan Reef, Belle River Mills Field, St. Clair County, Michigan, U.S.: AAPG Bulletin, v. 89, no. 4, p. 409-433.

6.0 FIGURES

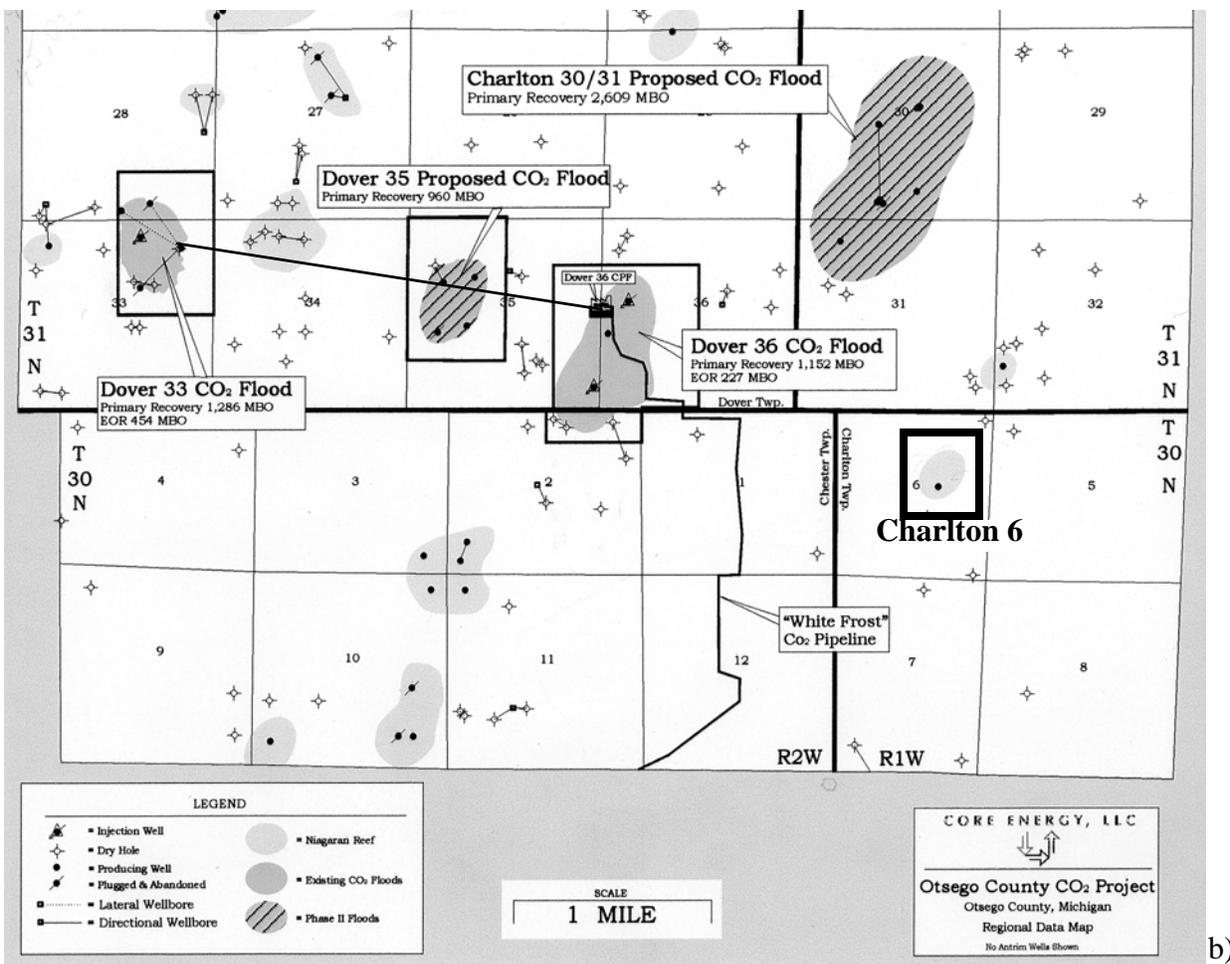
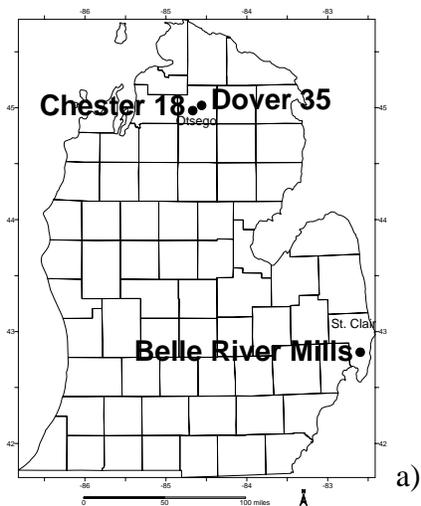


Figure 1. (a) Location of Dover 35, Chester 18 Fields in Otsego County, and Belle River Mills Field in St. Clair County, Michigan. (b) Location map for Dover 35 demonstration project area showing CO₂ supply and distribution pipelines, old demonstration site, Charlton 6 and new demonstration site, Dover 35 (courtesy of Core Energy, LLC).

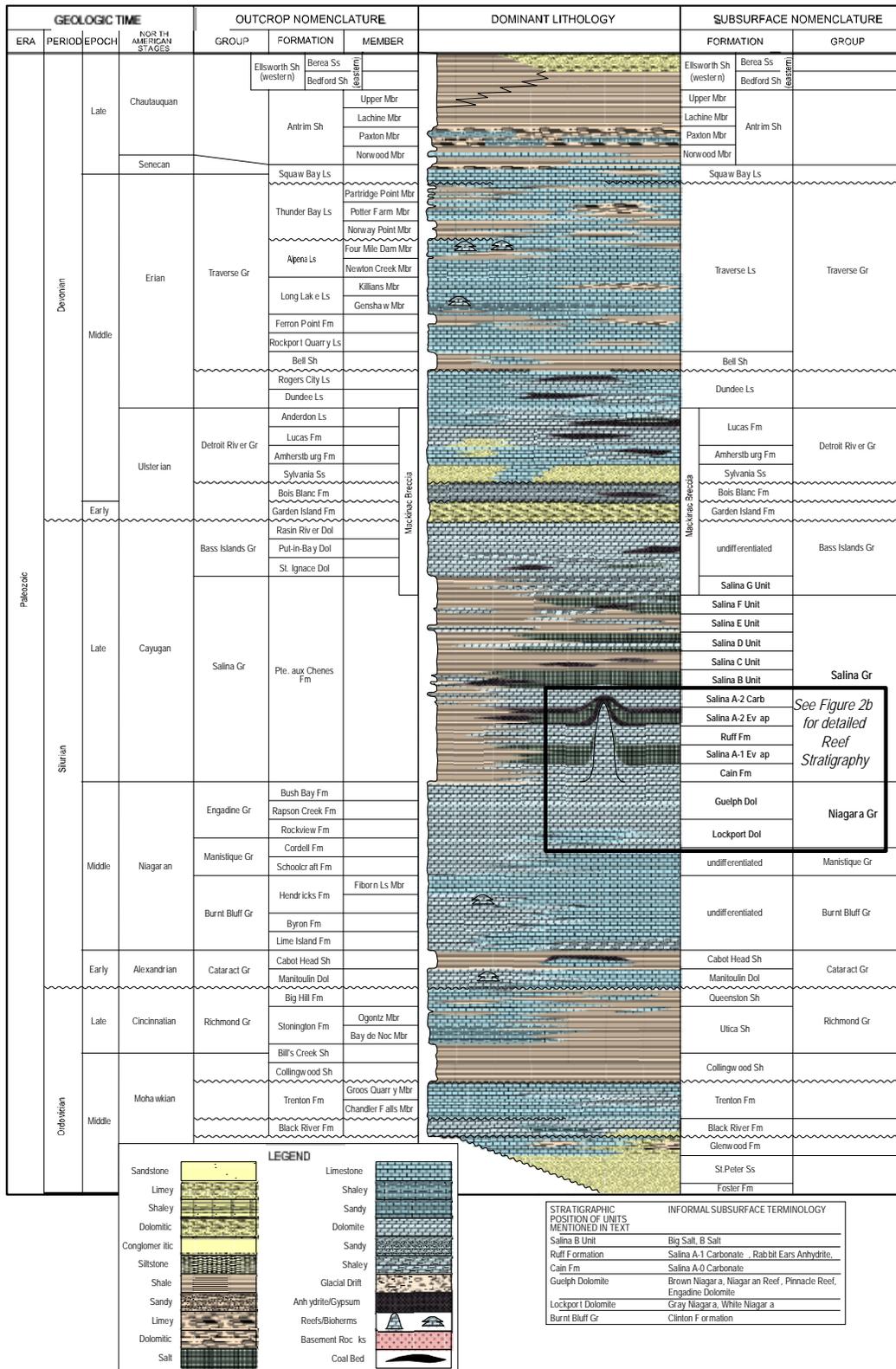


Figure 2a. Generalized stratigraphic column for the Michigan Basin.

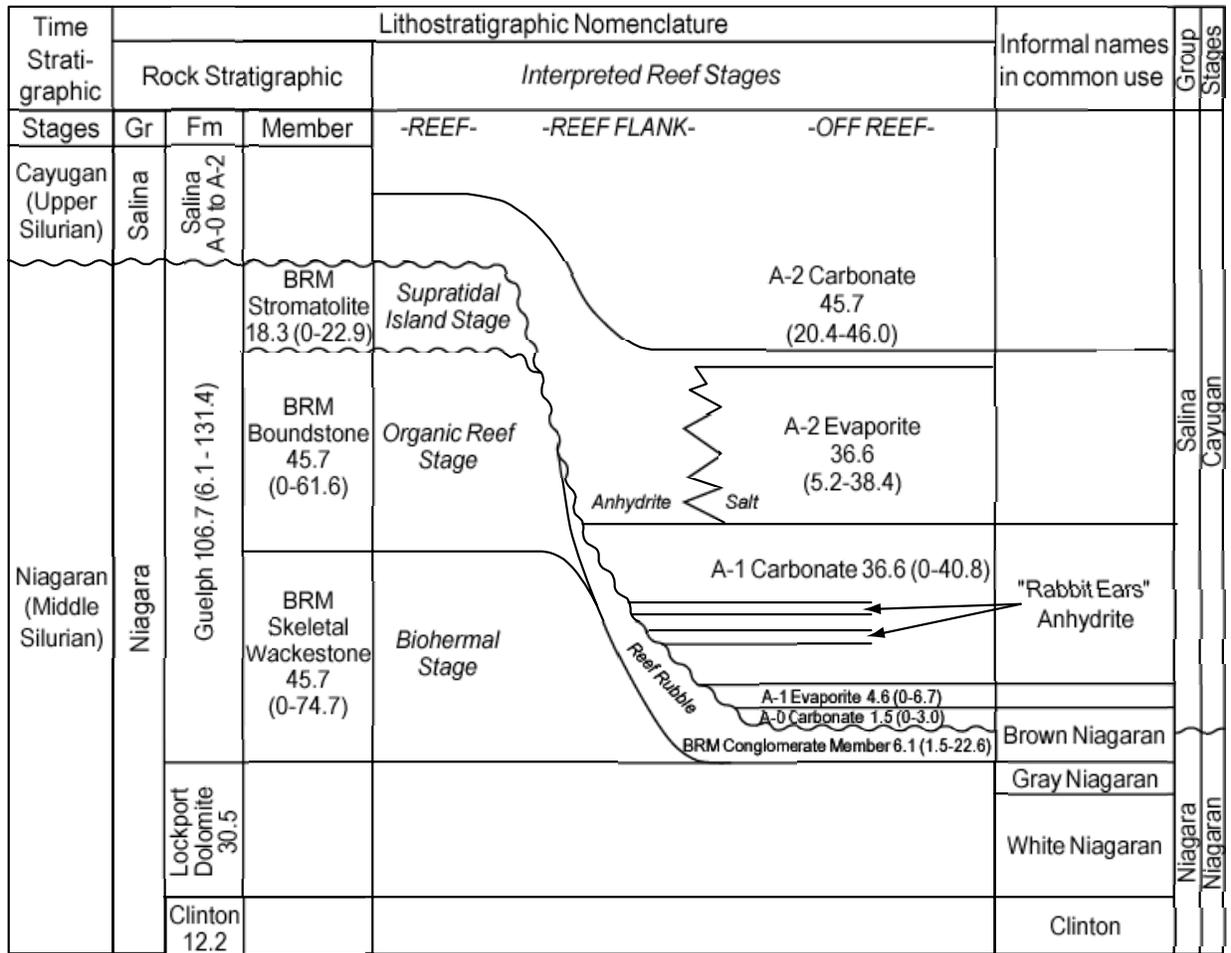


Figure 2b. Stratigraphic column showing subsurface nomenclature and correlations in the vicinity of the Belle River Mills Field (BRM), St. Clair County, Michigan as described by Gill (1977a) and reprinted with the permission of the Michigan Basin Geological Society. Average rock unit thicknesses and thickness ranges are shown in meters. Gill's subsurface nomenclature is followed in the text.

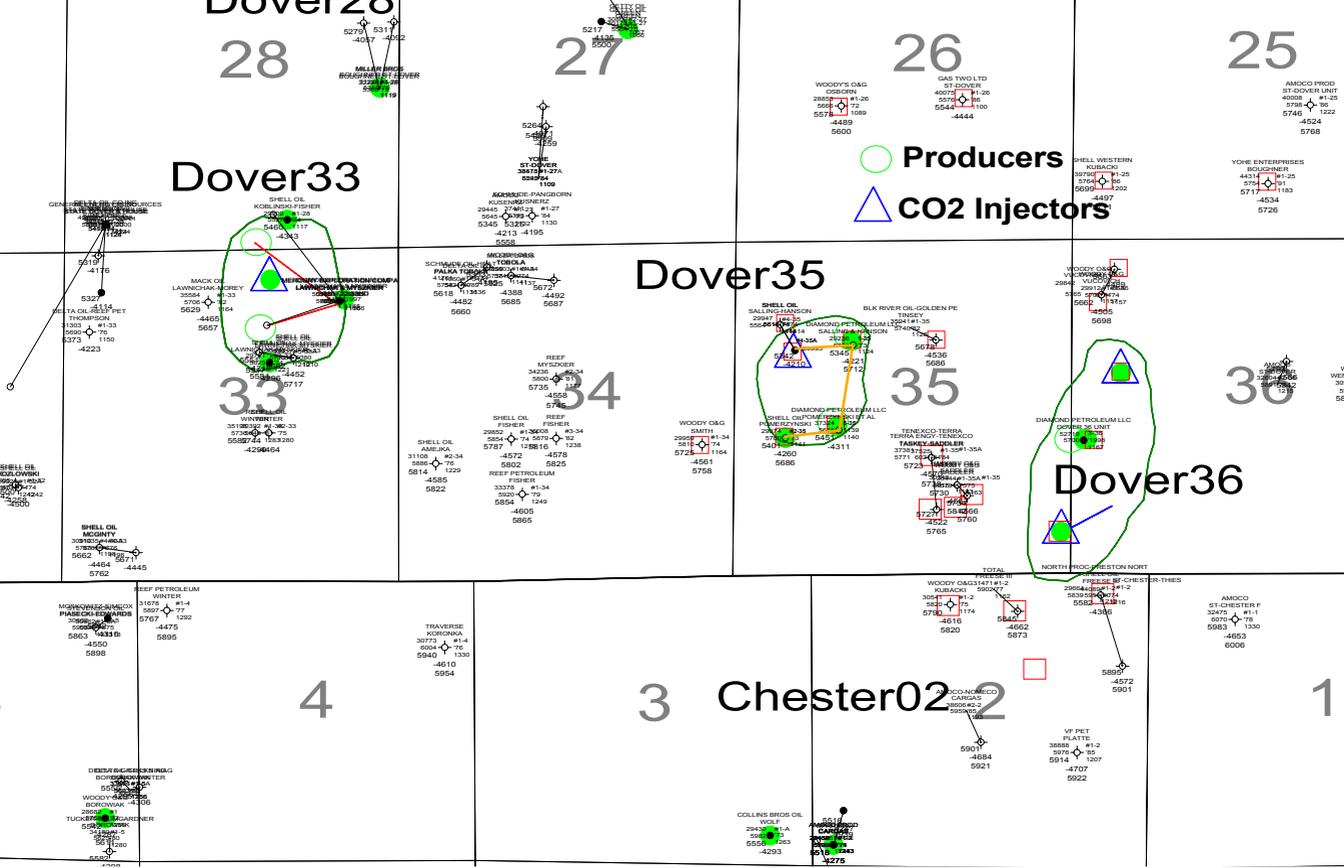


Figure 3. Location map for Dover 35 Field area. The 4 wells in the field are shown inside the green outline. The Salling-Hansen # 4-35 and Salling-Hansen #1-15 wells are the current CO₂ injector wells and the Pomerzynski #5-35 is the current producer in the demonstration project. Data posted around the well spots is operator, well name, well number, year drilled, KB, permit number, total depth, top Niaganran Brown measured and subsea depths, and top Niaganran Gray measured depth; small well spots are shallow Antrim wells. Section 35 is one square mile. North is towards the top of the map. Orange lines indicate the cross section shown in Figure 19.

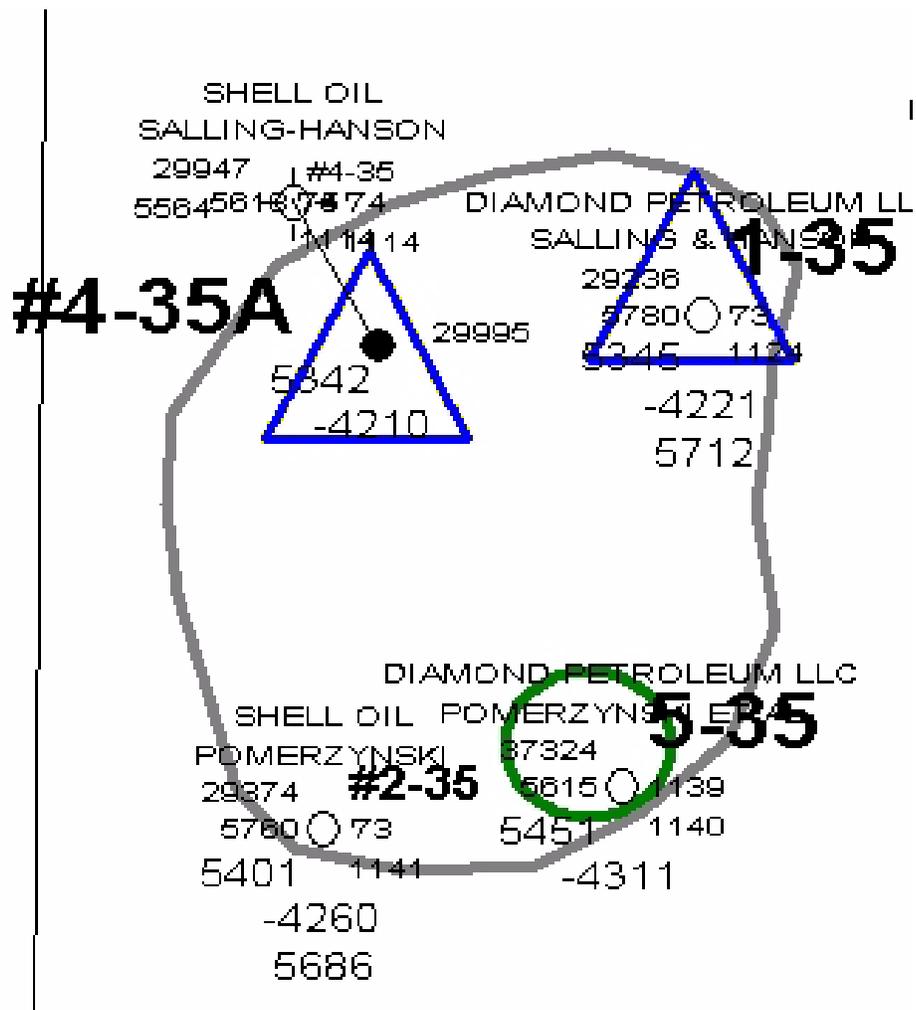


Figure 4. Detail map of Dover 35 CO₂ injection field in Otsego County, Michigan. Green well spot indicates the producing well and blue triangles indicate the two CO₂ injector wells. Location of Dover 35 is Section 35, T31N, R02W and North is toward the top of the page. Well 5-35 is 1480 feet south of well 1-35.

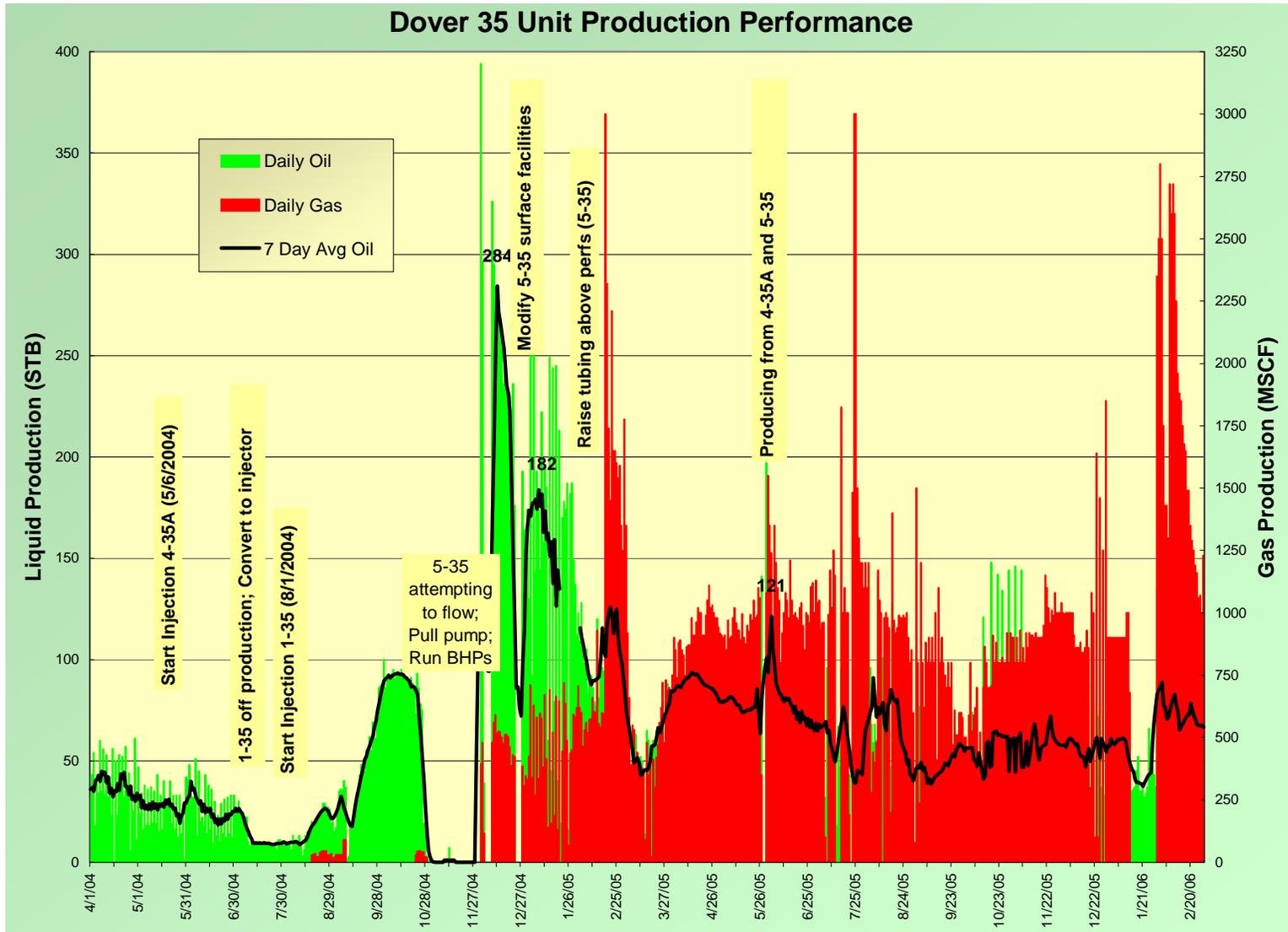


Figure 5. Dover 35 production performance graph showing gas (red), oil (green), seven-day average oil (black), and mechanical events for the startup of the CO₂ injection. STB is stock tank barrels of oil and MSCF is thousands of standard cubic feet of gas. Note the production response in the 5-35 well approximately 2 weeks after start of injection into the 1-35 well. Seven day average oil rates are shown for December 12, 2004 (284 bopd), January 9, 2005 (182 bopd) and June 2, 2005 (121 bopd).

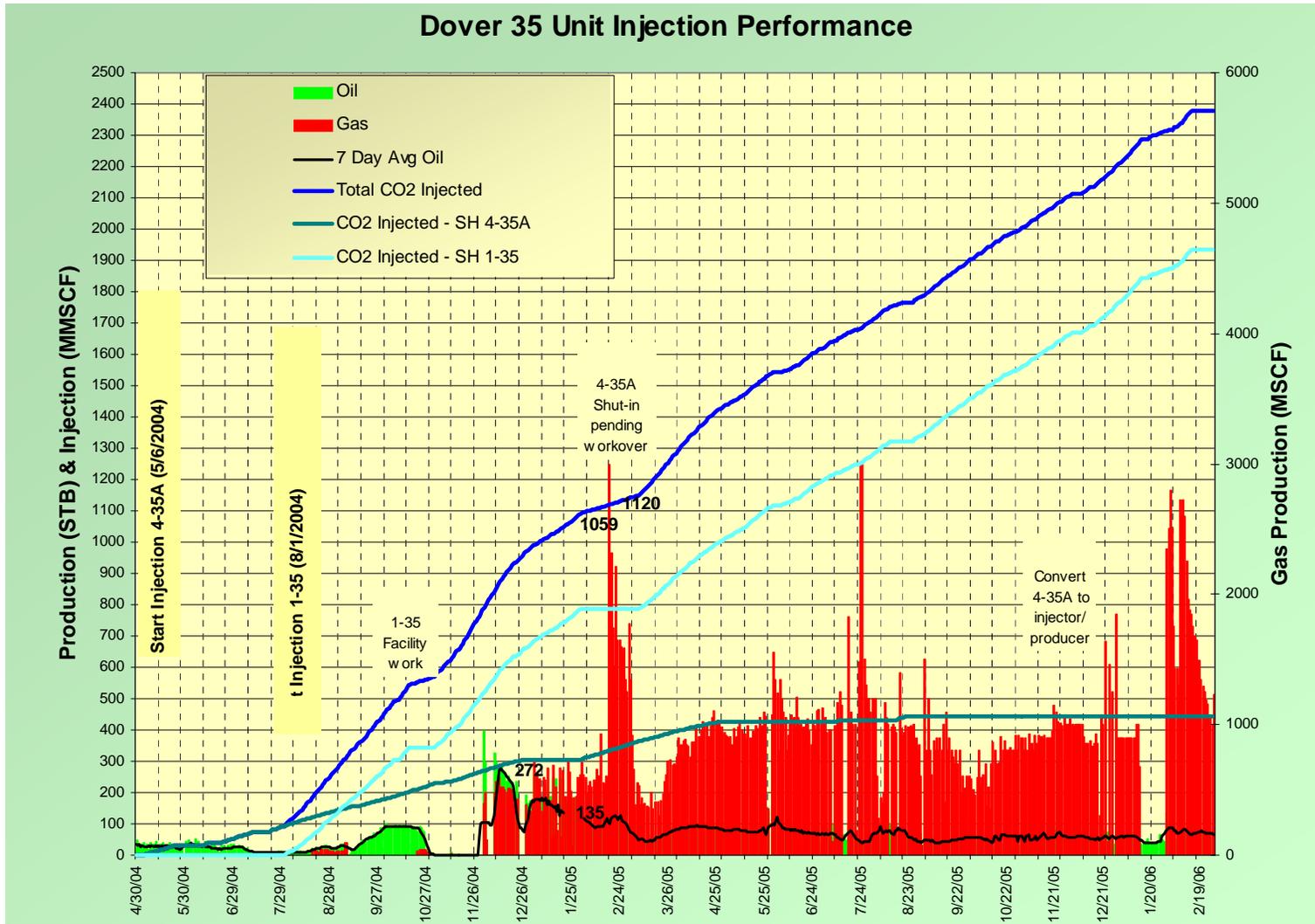


Figure 6. Dover 35 production and CO₂ injection performance showing gas (red), oil (green), seven-day average oil (black), individual cumulative injection by well (4-35A and 1-35), and cumulative CO₂ injection. CO₂ injection began on May 6, 2004 into the 4-35A, and on August 1, 2004 into the 1-35. Seven day average oil rates are shown for December 13, 2004 (272 bopd) and January 20, 2005 (135 bopd). Original graph courtesy of Core Energy, LLC.

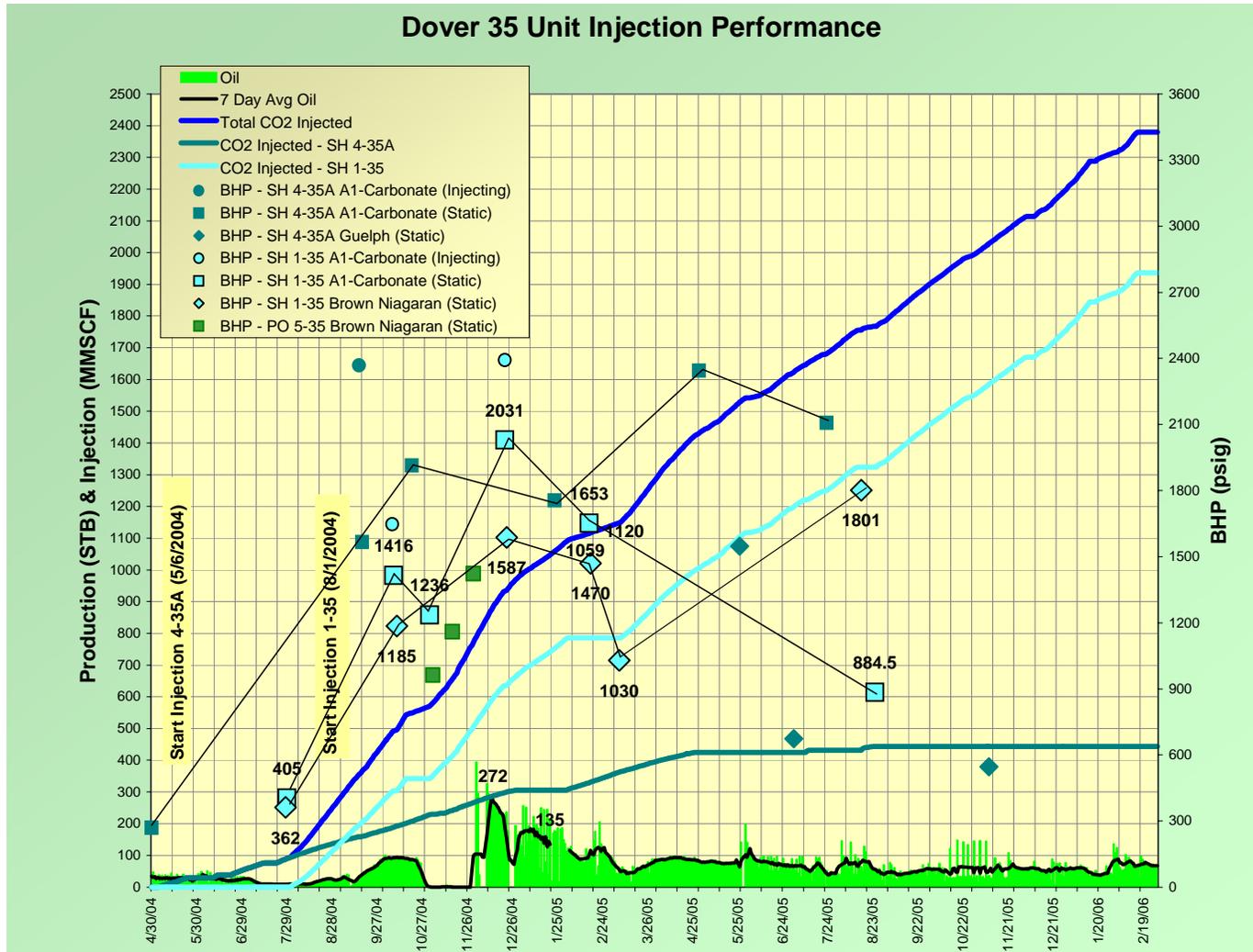


Figure 7. Dover 35 production and CO₂ injection performance and bottom hole pressure (BHP) build-up test results. The static BHP tests in the 1-35 well indicate a divergence in pressure increase between the A1-Carbonate (injection interval in the 4-35A and 1-35) and the Brown Niagaran. The BHP divergence between these two zones clearly indicates that CO₂ mobility is being affected by heterogeneity in the carbonate reservoir. Seven day average oil rates are shown for December 13, 2004 (272 bopd) and January 20, 2005 (135 bopd). Static bottom hole pressure values for the 1-35 are also posted on the chart. Static BHP trend lines added for clarity. Original graph courtesy of Core Energy, LLC.

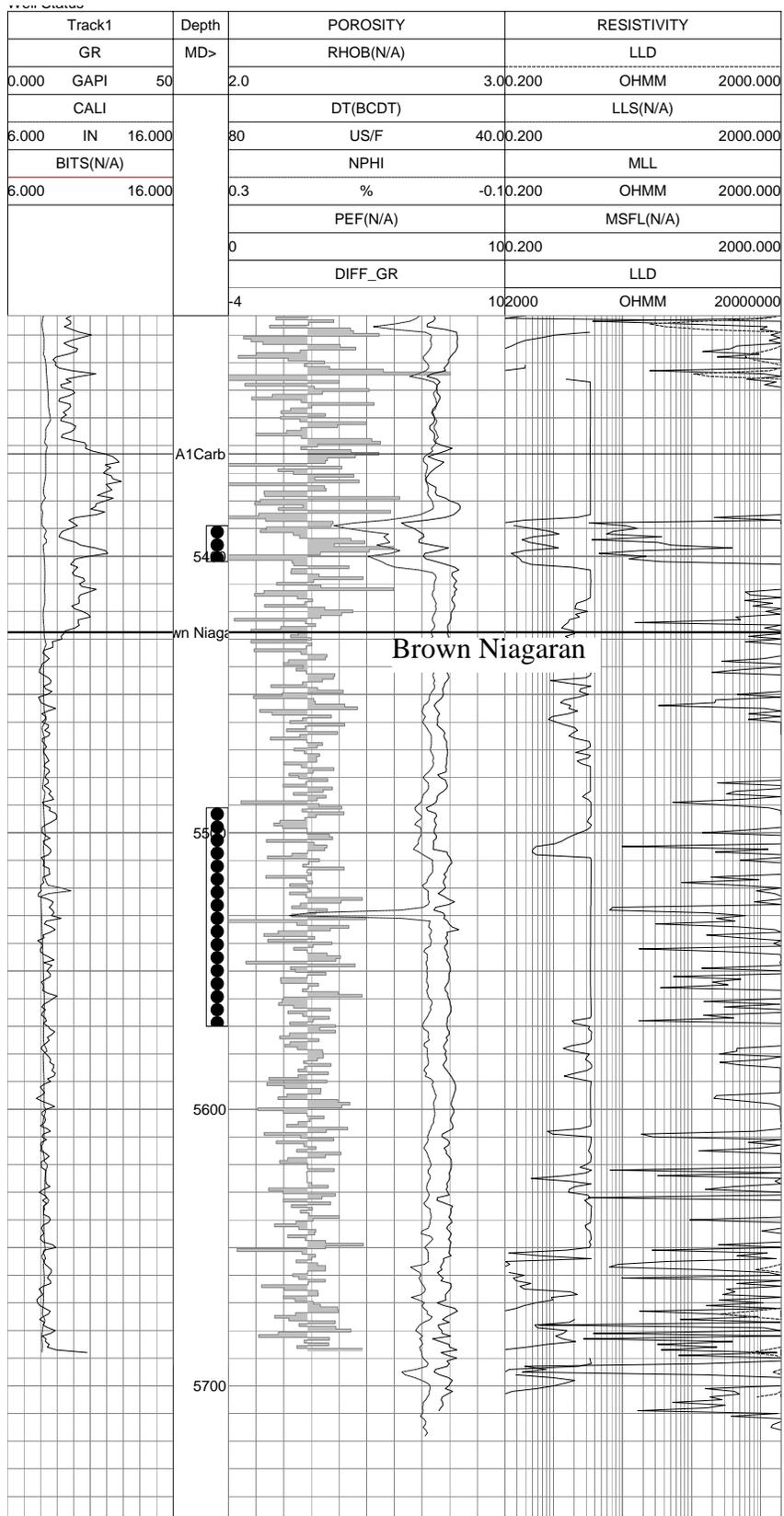


Figure 8. Salling-Hanson 4-35A well log curves and perforated intervals.

Salling Hanson Trust 4-35A

UIC Permit No. 137-2R-0009

MI Permit No. 29995

Well Construction As of 6/18/2004

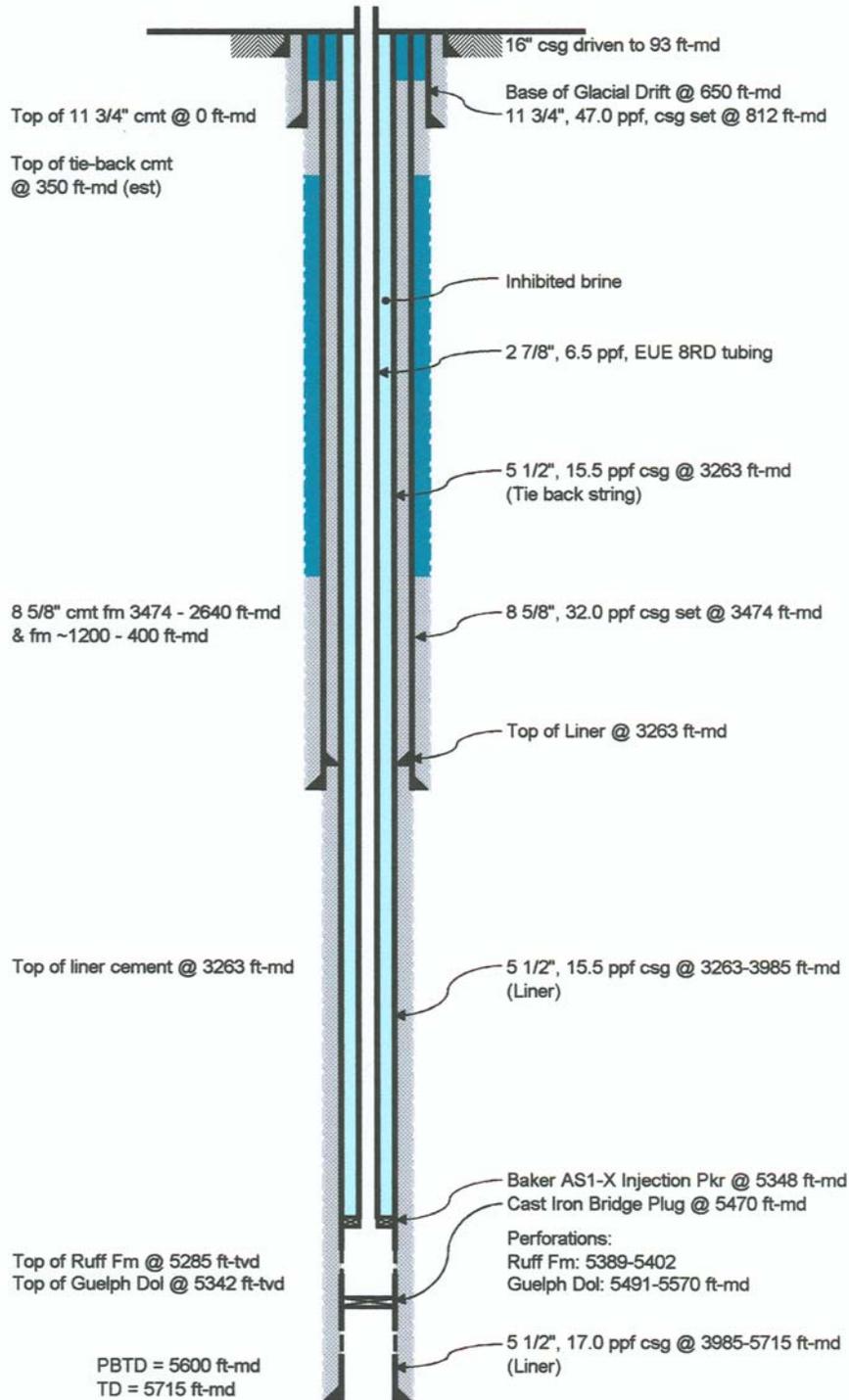


Figure 9. Salling-Hanson 4-35A well bore diagram showing downhole mechanical configurations. Diagram provided by Core Energy, LLC.

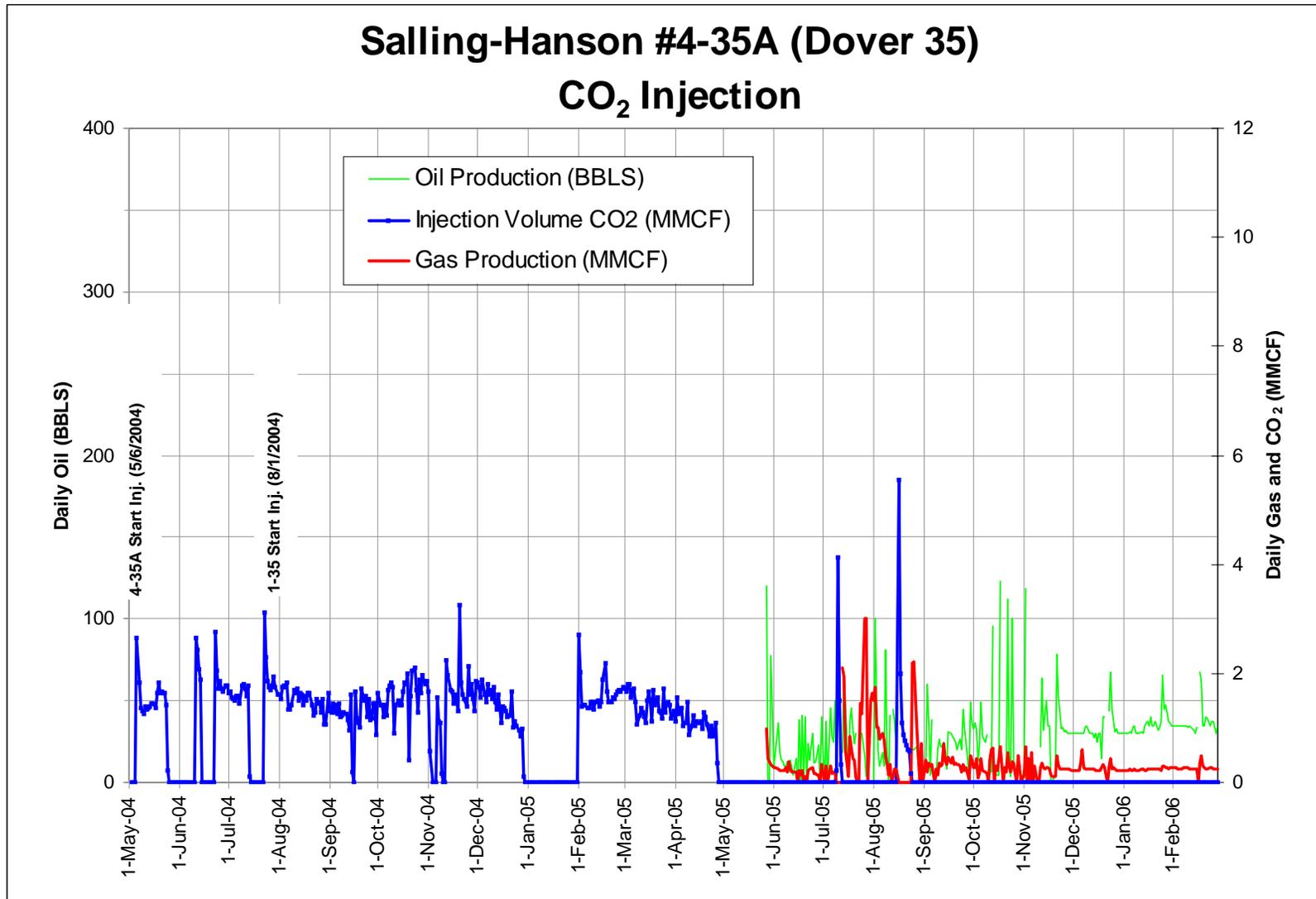


Figure 10. Salling-Hanson 4-35A daily CO₂ injection chart. The well was shut-in on December 29, 2004 in preparation for a work-over of the well bore, and also in May 2005 to reconfigure the well with two packers and a sliding sleeve so it can be used as either a producing well or as a CO₂ injector well.

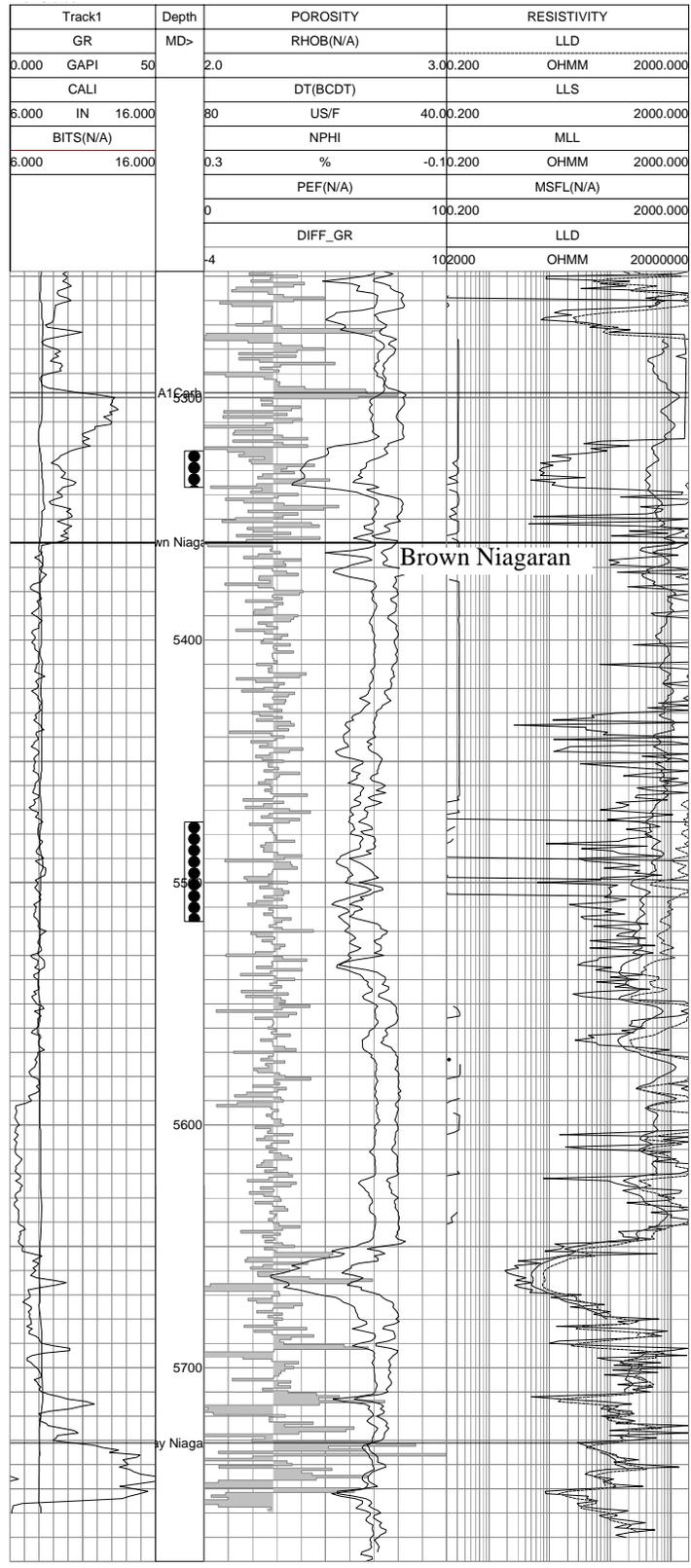


Figure 11. Salling-Hanson 1-35 well log curves and perforated intervals.

Salling Hanson Trust 1-35

Injection Well

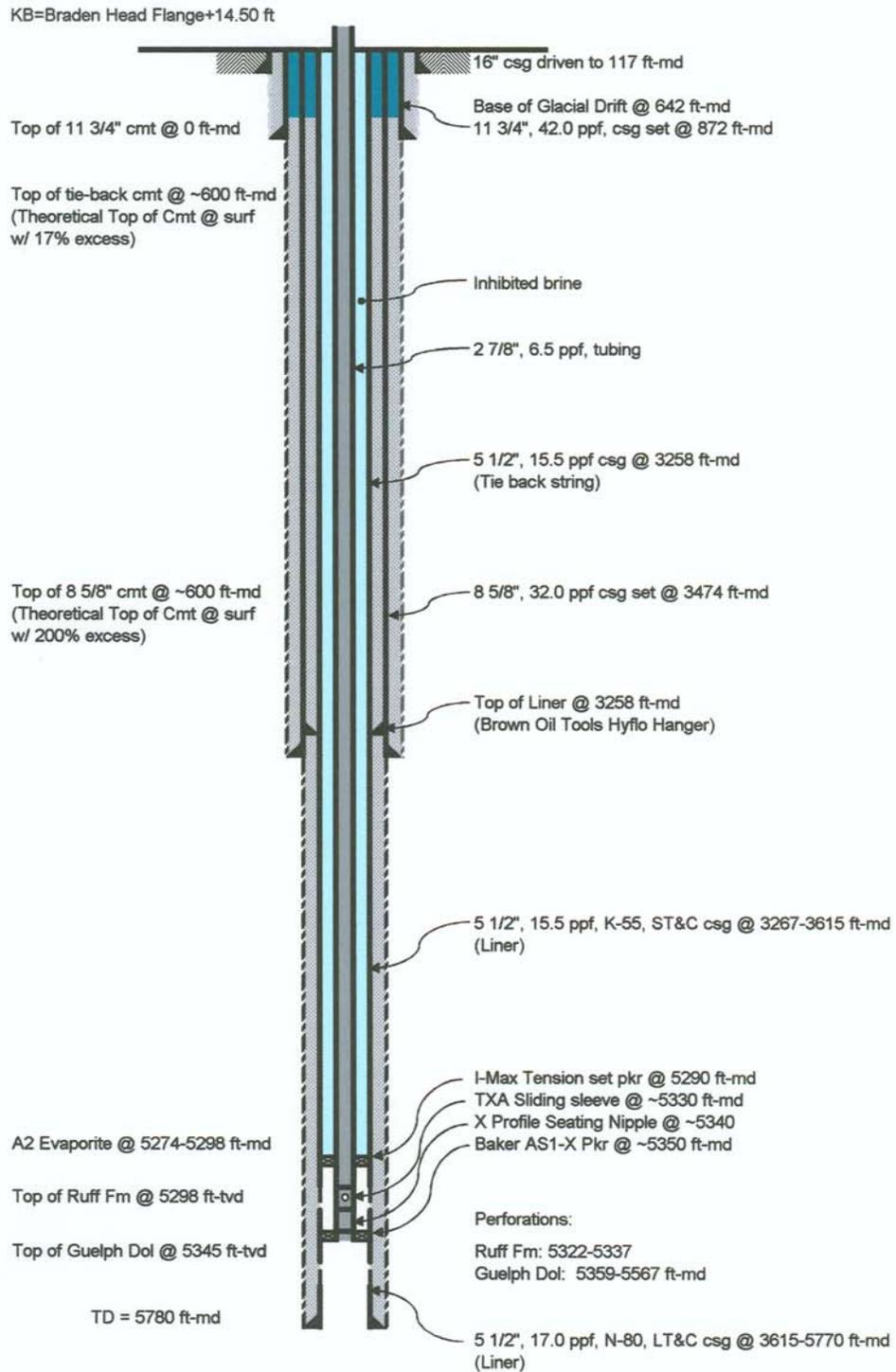


Figure 12. Salling-Hanson 1-35 well bore diagram showing downhole mechanical configurations. Diagram provided by Core Energy, LLC.

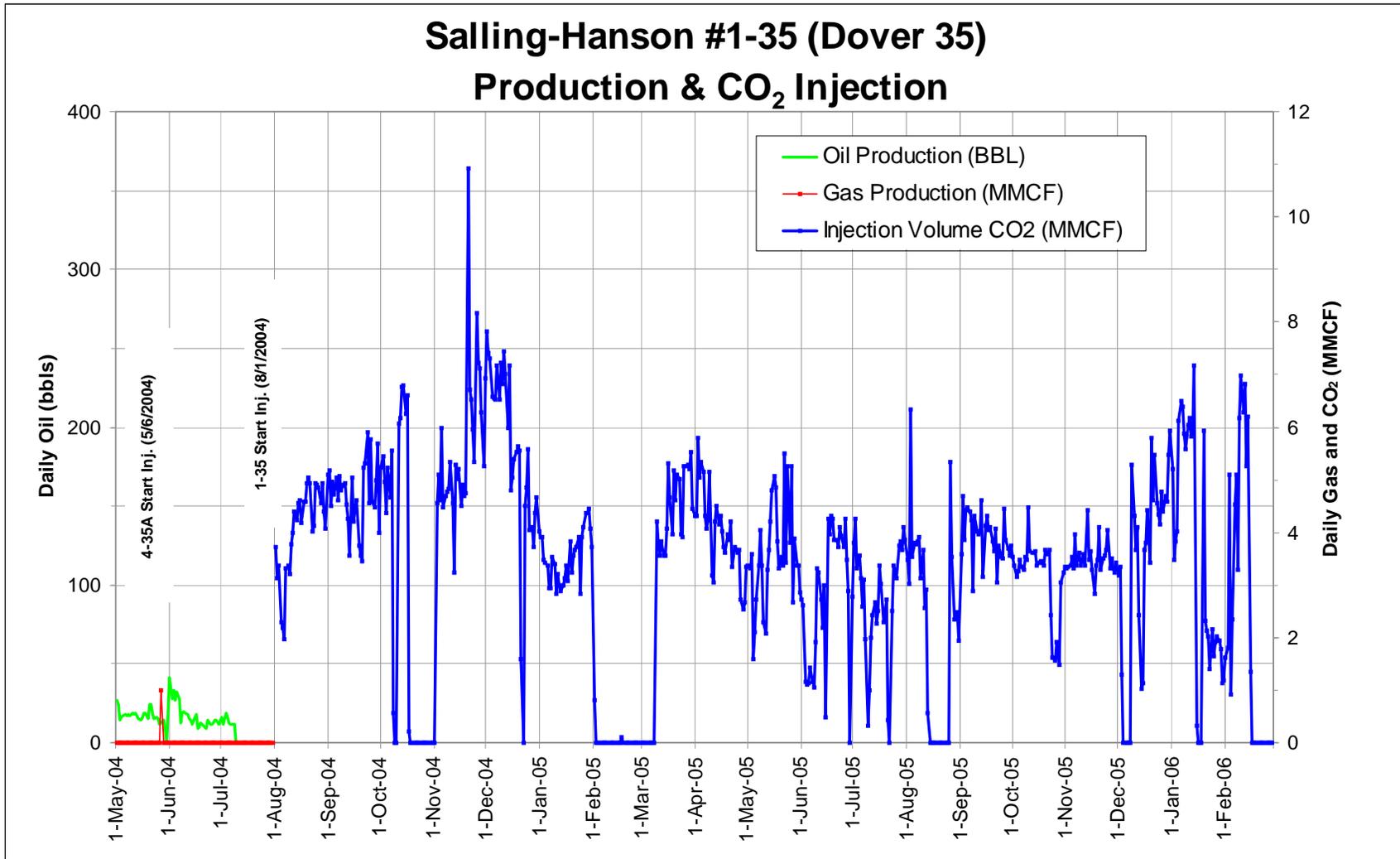


Figure 13. Salling-Hanson 1-35 daily production and CO₂ injection chart. The 1-35 was converted in July, 2004 from a producing well to the second CO₂ injection well in the Dover 35 field.

Well Pomerzynski 5-35
 Well ID 21137373240000
 Field Dover 35
 County Otsego
 State/Prov
 Country U.S.A
 Legal Description
 Well Status

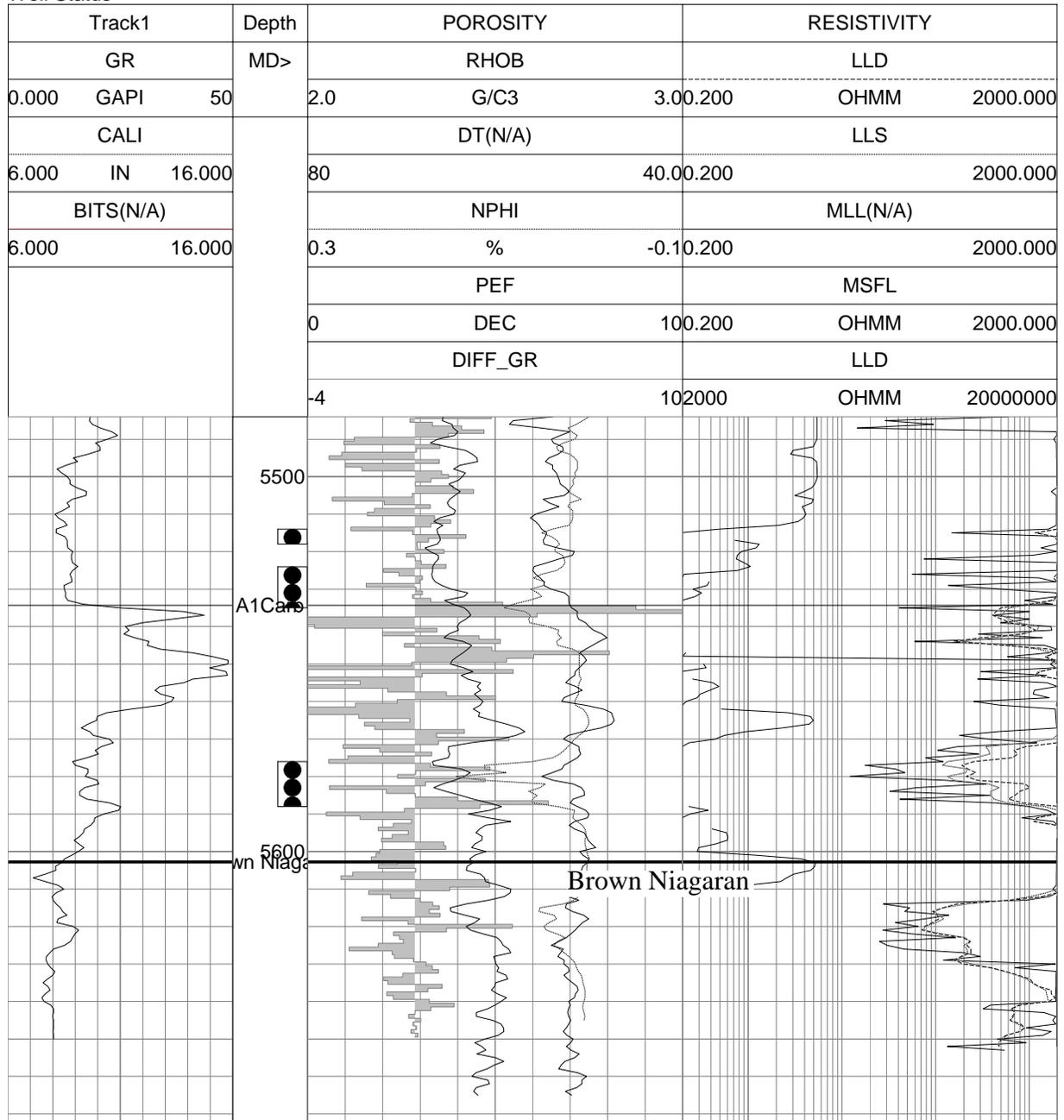


Figure 14. Pomerzynski 5-35 well log curves and perforated intervals.

Pomarzynski et al 5-35

UIC Permit No. MI-137-2R-0010

MI Permit No. 37324

Well Construction As of 1/20/2005

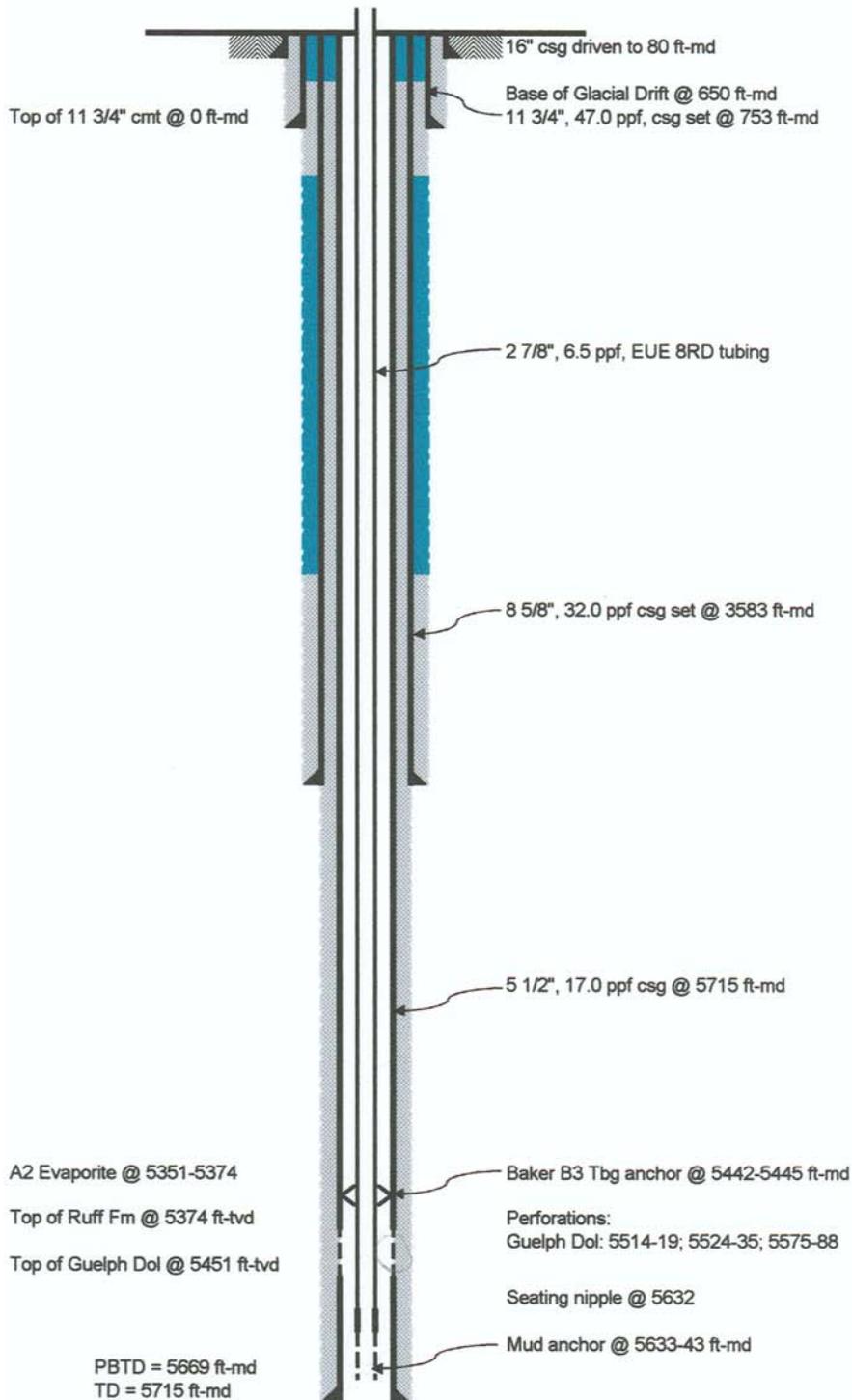


Figure 15. Pomerzynski 5-35 well bore diagram showing downhole mechanical configurations. Diagram provided by Core Energy, LLC.

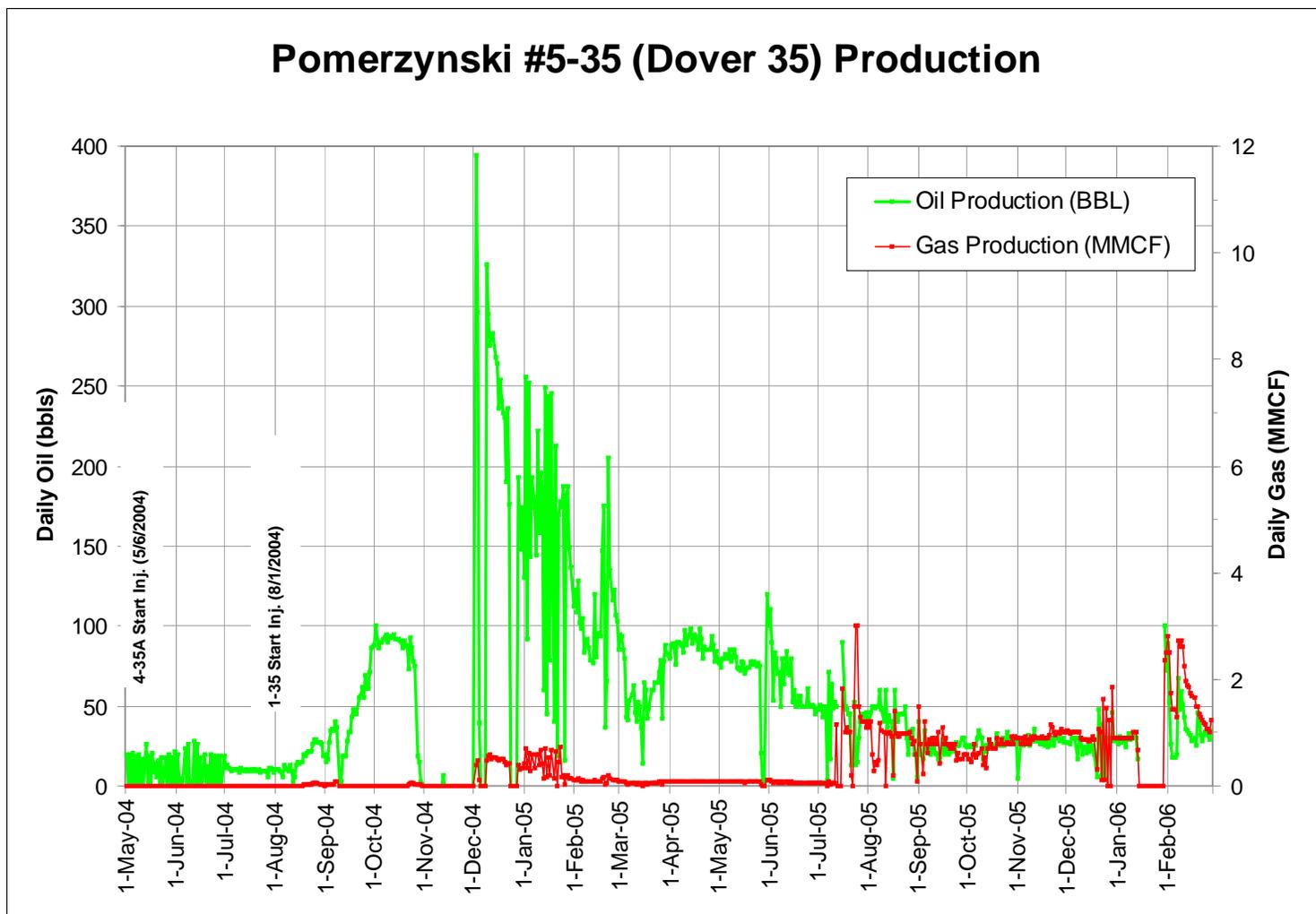


Figure 16. Pomerzynski 5-35 daily production chart. Production response was seen in this well within two weeks of CO₂ injection start-up in the 1-35. During October, 2004 the well began to produce significant gas and was attempting to flow. During November, 2004, the well was converted from pumping to flowing, and after swabbing, produced over 200 bopd. However the well continued to experience fluid loading problems because the base of the tubing was below the perforations. The well was worked over to raise the tubing above the perforations to improve production performance.

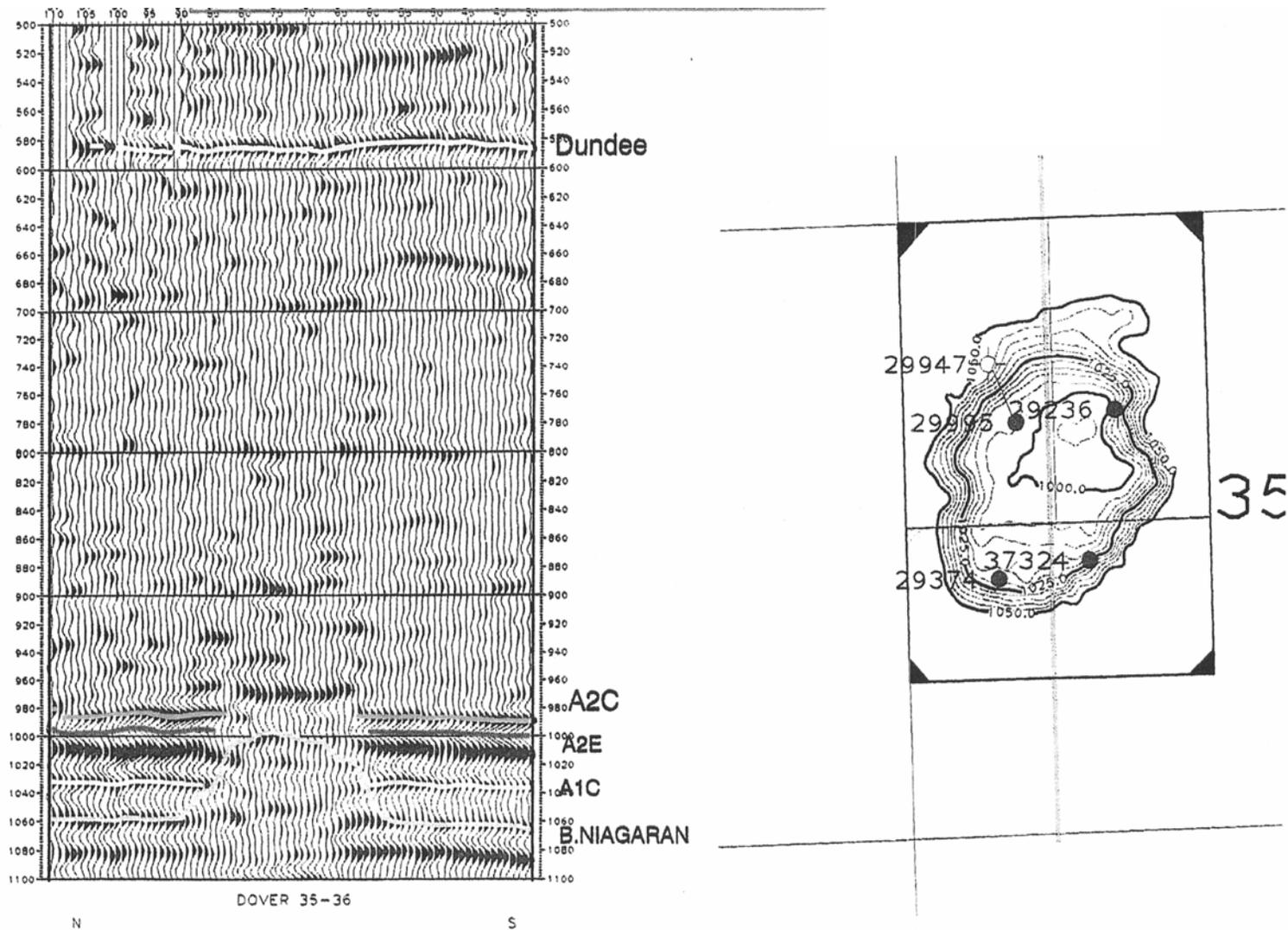


Figure 18. Example west-east panel through Dover 35 3D seismic volume provided by industry partner. Note absence of seismic reflections over the Dover 35 field that is a characteristic seismic signature of Niagaran reefs.

Reservoir Characteristics	Dover 35	Dover 33	Dover 36
Reservoir Geologic Type	Pinnacle Reef	Pinnacle Reef	Pinnacle Reef
Reservoir Geologic Age	Silurian	Silurian	Silurian
Lithology	Dolomite/Limestone	Dolomite	Dolomite/Limestone
Depth (top reservoir)	5,320'	5,300'	5,320'
Field Area	~85 Acres	93 Acres	195 Acres
Porosity Type	Vugular and intercrystalline	Vugular and intercrystalline	Vugular and intercrystalline
Average Porosity	8.0% (est.)	7.1%	6.9%
Permeability	Unknown - No Cores	Unknown - No Cores	Unknown - No Cores
Reef Thickness	410' (includes A-1carb zone)	360'	370'
Oil Column Thickness	~220' (includes A-1)	214'	300'
Average Water Saturation	25%	22%	25%
Crude Oil Gravity	41.5 ^o	43.6 ^o	42.8 ^o
Initial Reservoir Pressure (psia)	2946	2894	2996
Reservoir Temperature	104 ^o F	108 ^o F	108 ^o F
Bubble Point Pressure (psia)	2050	2100	1870
Initial Solution GOR (scfg/stbo)	450	650	608
OOIP by Material Balance	2.2 MMstbo	4.1 MMstbo	3.64 MMstbo
MMP (psia)	1195	1195 (2.7bcf, 9 months)	1195 (2.1bcf, 29 months)
Primary Production	0.966 MMBO & 0.835MMCFG	1.28MMBO & 1.87MMCFG	1.149 MMBO & 1.17MMCFG
Oil Recover Factor (primary)	~33%	31.2%	31.6%
Drive Mechanism	Pressure Depletion, Gravity Segregation	Pressure Depletion, Gravity Segregation	Pressure Depletion, Gravity Segregation

Figure 20. Table comparing reservoir characteristics between Dover 35, Dover 33 and Dover 36 fields.

Historical and Predicted Performance - Dover 35, 33 & 36 CO₂ EOR Projects

	<u>PUMPIII Dover 35</u>	<u>Dover 33</u>	<u>Dover 36</u>
Start Date of CO ₂ injection	May-2004	May-1996	Jan-1997
Cumulative oil production @ start of CO ₂ injection	966 MBO	1,280 MBO	1,149 MBO
Estimated ultimate primary oil production	992 MBO	1,360 MBO	1,160 MBO
Estimated original oil in place (material balance)	2,243 MBO	4,100 MBO	3,730 MBO
Volume of oil produced since CO ₂ injection	39 MBO*	480 MBO*	257 MBO*
Estimated remaining oil reserves	235 to 585 MBO	300 MBO	Unknown
Estimated ultimate oil recovery (primary + CO ₂)	1,234 MBO	2,027 MBO	Unknown
Estimated ultimate oil recovery by CO ₂ process	250 to 600 MBO	750 MBO	Unknown
Total CO ₂ injected (initial & recycled)	2.214 BCF*	20.5 BCF**	6.3 BCF***
Other substances injected:			
Water		11,000 Bbls	0
Other Substances		0	0
	*as of December 2005	** as of December 2003	*** as of January 2005
CO ₂ injected to reach minimum miscibility pressure (1200 psi)	in progress	2.7 BCF	2.1 BCF

Figure 21. Historical and predicted performance for Dover 35, Dover 33 and Dover 36 fields, including cumulative production, reserves, and estimated ultimate recovery.

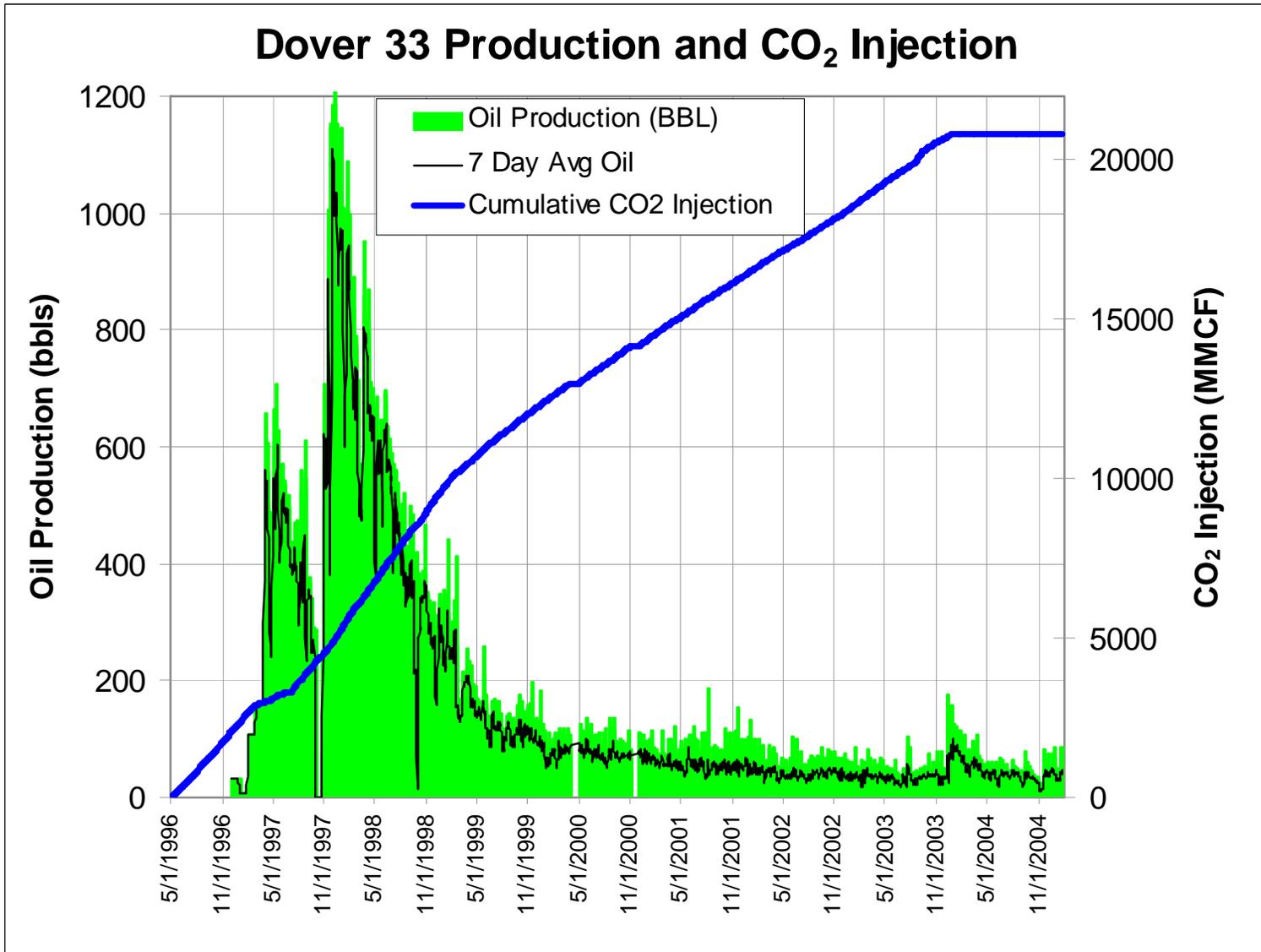


Figure 22. Dover 33 daily oil production and cumulative CO₂ injection.

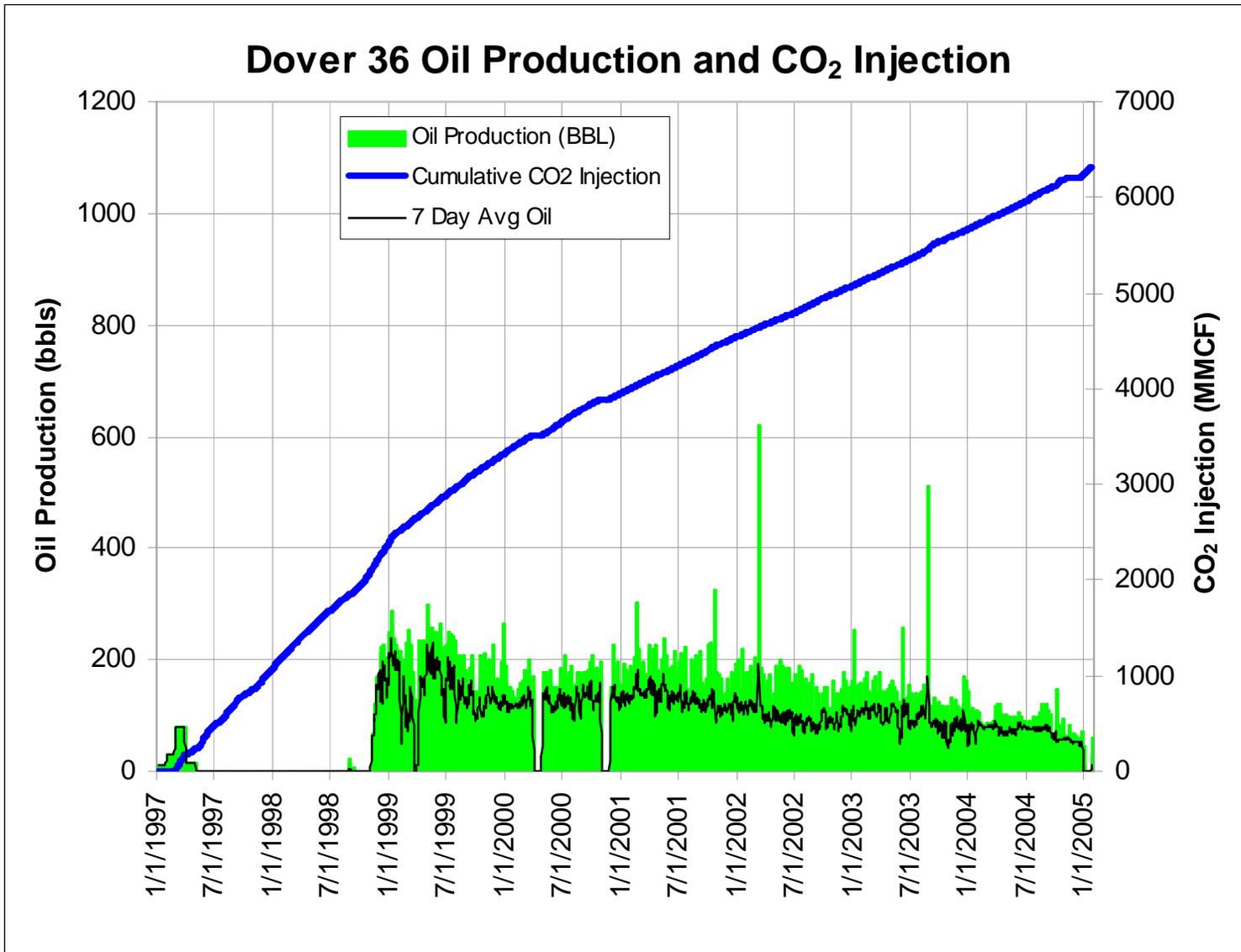
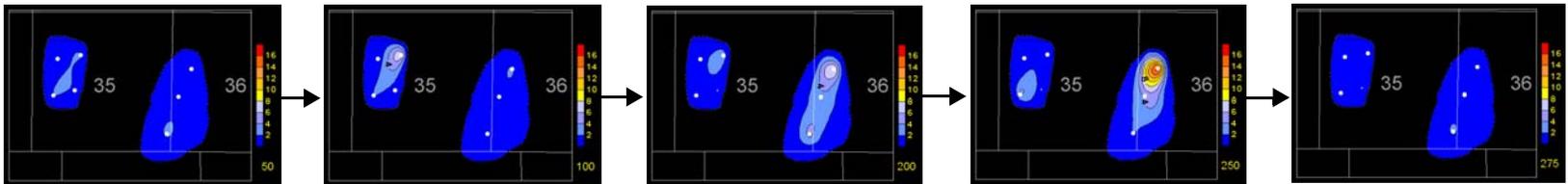
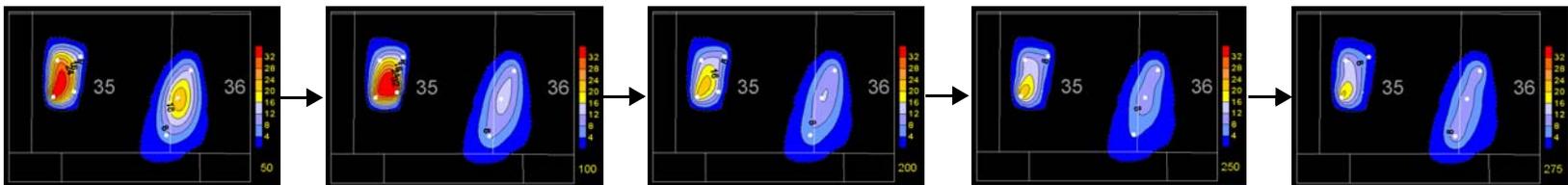


Figure 23. Dover 36 daily oil production and cumulative CO₂ injection.

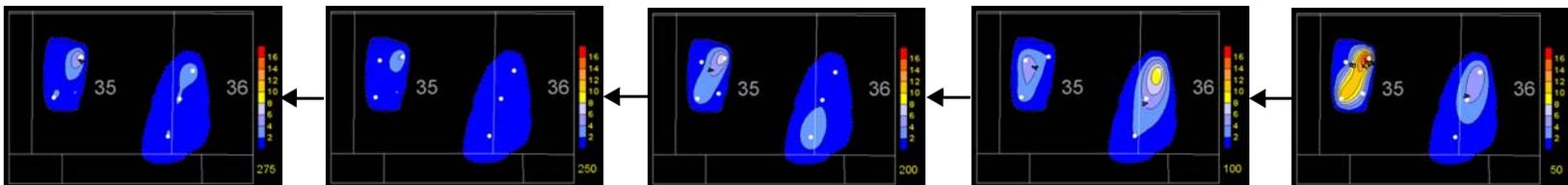
LOG POROSITY: TOP-DOWN SLICING FROM REEF TOP TO REEF BASE



GAMMA RAY: TOP-DOWN SLICING FROM REEF TOP TO REEF BASE



LOG POROSITY: BOTTOM-UP SLICING FROM REEF BASE TO REEF TOP



GAMMA RAY: BOTTOM-UP SLICING FROM REEF BASE TO REEF TOP

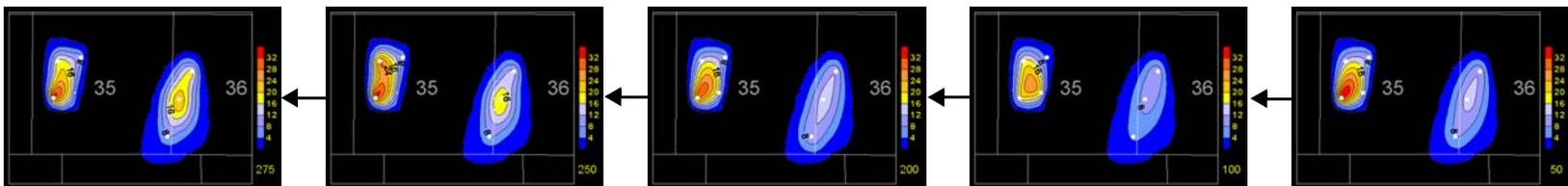


Figure 24. Dover 35 and Dover 36 Well Log Tomography slices. Color Scale is in percent porosity with a Contour Interval of 2 phi for Log Porosity slices, and Color Scale is in API units with a Contour Interval of 4 api for Gamma Ray slices. Slice number is feet above reef base or below reef top. North is toward the top of each map.

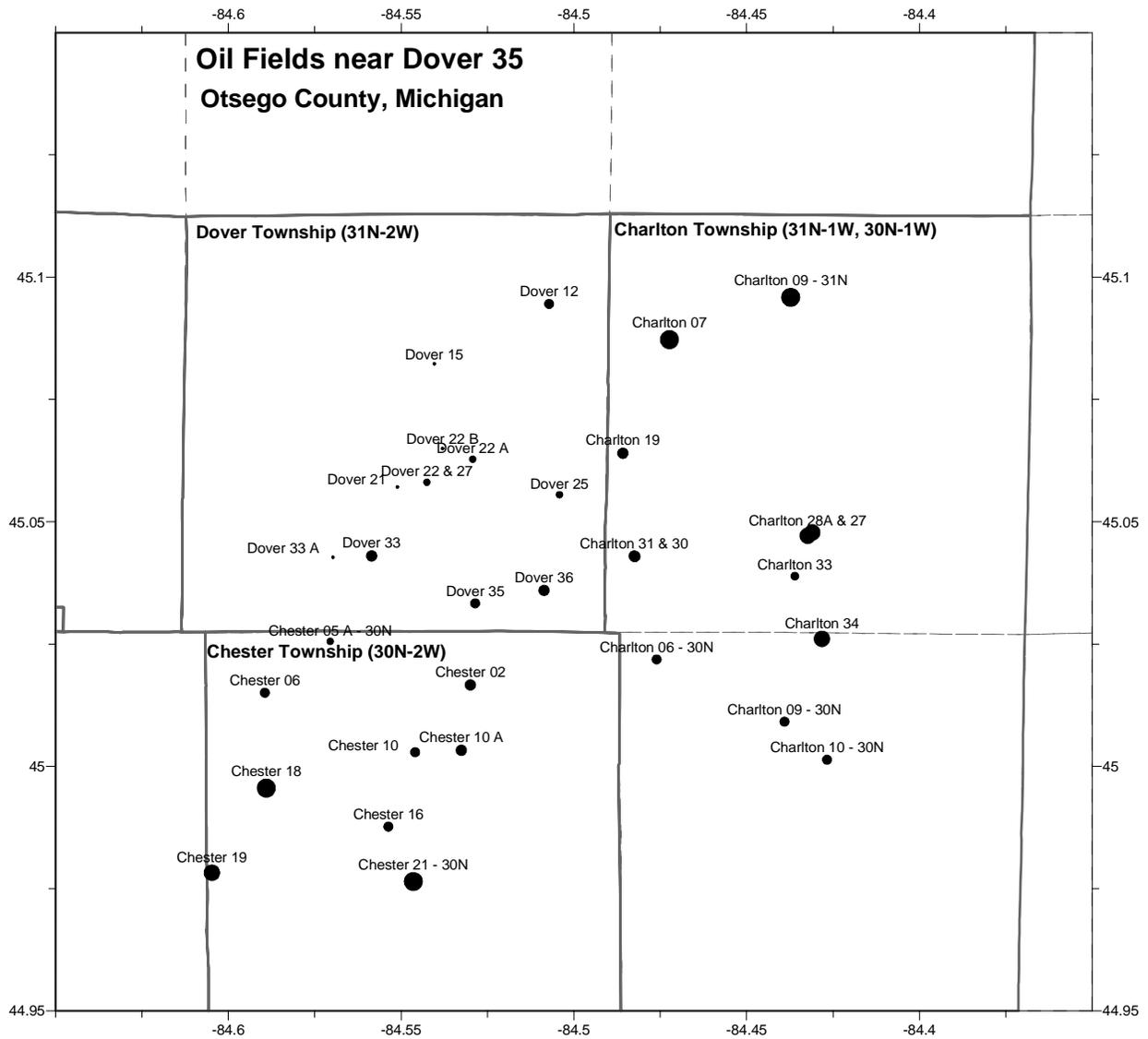


Figure 25. Map of pinnacle reefs near Dover 35 and Dover 33 in Otsego County, Michigan. Larger circles representing field locations indicate higher ratings for secondary recovery, and the smallest circles indicate poor secondary recovery ratings.

Field Number	Field	Number of Wells	IP (bbls) (1)	Calculated Secondary Oil Recovery (IP * .373) (2)	Secondary Oil Recovery (bbls) Actual-to-date	Ratio: IP / Dover 33 IP	Rating (3)
724	Chester 18 - 30N - 02W	26	11,210,794	4,181,626		8.71	A
727	Chester 21 - 30N - 02W	9	8,241,656	3,074,138		6.40	A
696	Charlton 09 - 31N - 01W	3	4,427,369	1,651,409		3.44	A
694	Charlton 07 - 31N - 01W	10	3,470,930	1,294,657		2.70	A
712	Charlton 34 - 31N - 01W	10	3,080,613	1,149,069		2.39	B+
725	Chester 19 - 30N - 02W	4	2,511,029	936,614		1.95	B+
705	Charlton 27 - 31N - 01W	5	2,497,219	931,463		1.94	B+
707	Charlton 28 A - 31N - 01W	4	1,886,842	703,792		1.47	B+
708	Charlton 30 - 31N - 01W	2	1,418,775	529,203		1.10	C
743	Dover 36 - 31N - 02W	4	1,417,206	528,618	257,448	1.10	C
723	Chester 16 - 30N - 02W	5	1,330,970	496,452		1.03	C-
740	Dover 33 - 31N - 02W	8	1,287,362	480,186	480,207	1.00	C
720	Chester 10 A - 30N - 02W	2	1,261,309	470,468		0.98	C
717	Chester 06 - 30N - 02W	3	1,222,848	456,122		0.95	C-
710	Charlton 31 - 31N - 01W	3	1,189,608	443,724		0.92	C
713	Chester 02 - 30N - 02W	6	1,025,554	382,532		0.80	C
1983	Charlton 19 - 31N - 01W	3	984,454	367,201		0.76	C
735	Dover 12 - 31N - 02W	2	976,894	364,381		0.76	C-
742	Dover 35 - 31N - 02W	5	960,451	358,248	38,947	0.75	C-
697	Charlton 10 - 30N - 01W	2	729,845	272,232		0.57	C-
693	Charlton 06 - 30N - 01W	1	629,949	234,971		0.49	C-
695	Charlton 09 - 30N - 01W	1	593,838	221,502		0.46	C-
719	Chester 10 - 30N - 02W	1	499,002	186,128		0.39	C-
711	Charlton 33 - 31N - 01W	3	463,932	173,047		0.36	D+
1876	Dover 25 - 31N - 02W	1	212,509	79,266		0.17	D
738	Dover 22 A - 31N - 02W	2	106,647	39,779		0.08	D
737	Dover 22 - 31N - 02W	1	93,051	34,708		0.07	D
716	Chester 05 A - 30N - 02W	1	81,369	30,351		0.06	D
736	Dover 21 - 31N - 02W	1	69,337	25,863		0.05	F
741	Dover 33 A - 31N - 02W	2	37,196	13,874		0.03	F
1932	Dover 15 - 31N - 02W	4	32,410	12,089		0.03	F
1259	Dover 27 - 31N - 02W	1	23,923	8,923		0.02	F
739	Dover 22 B - 31N - 02W	1	8,260	3,081		0.01	F
Notes:							
(1) IP - Initial Production							
(2) 0.373 is the ratio of initial production to secondary production for Dover 33							
(3) Ratings are based on Dover 33 = C							
(4) Dover 35 is project demonstration well; Dover 36 & Dover 33 have been placed on secondary CO2 recovery							

Figure 26. Table showing production, and potential secondary recovery ratings for pinnacle reefs near Dover 33 and Dover 35.

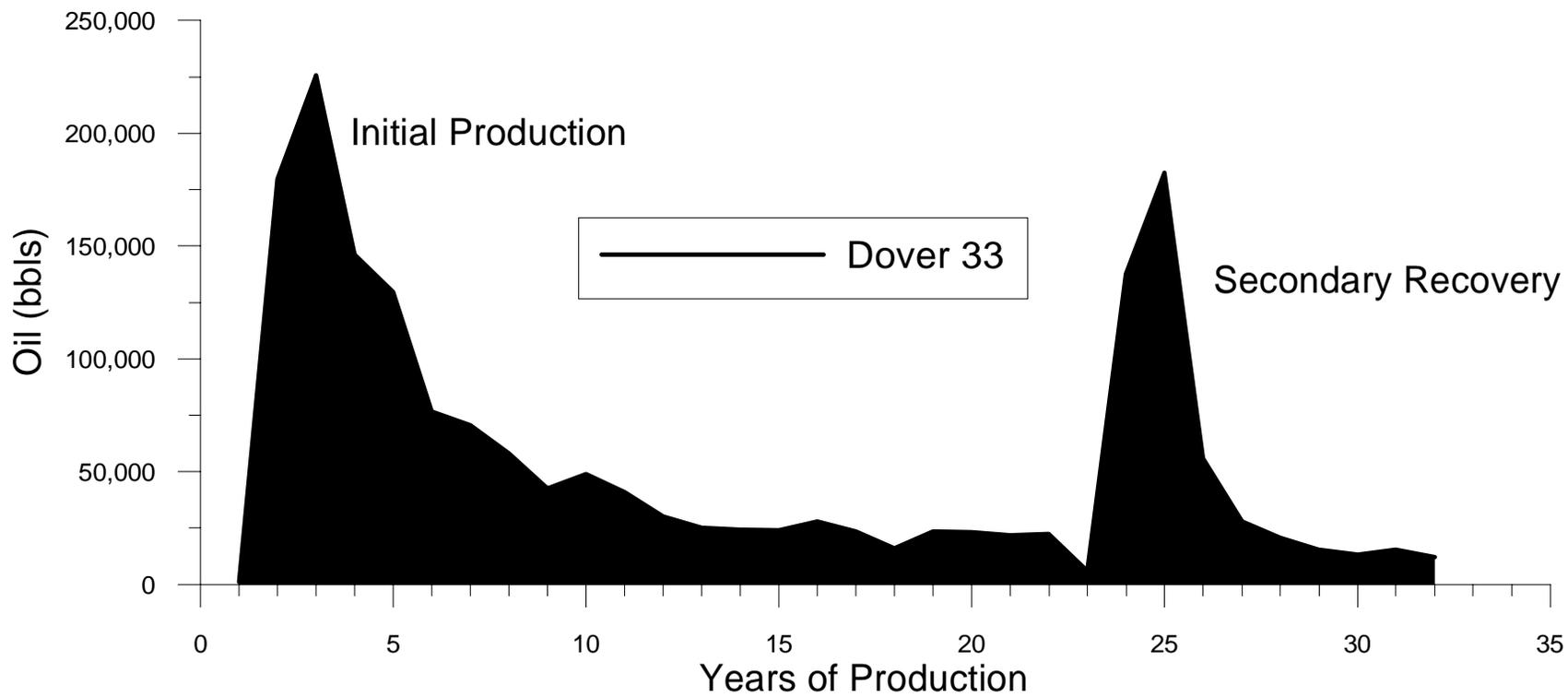


Figure 27. Production curve for Dover 33, showing the initial production and then the secondary recovery using CO₂ injection starting in year 23.

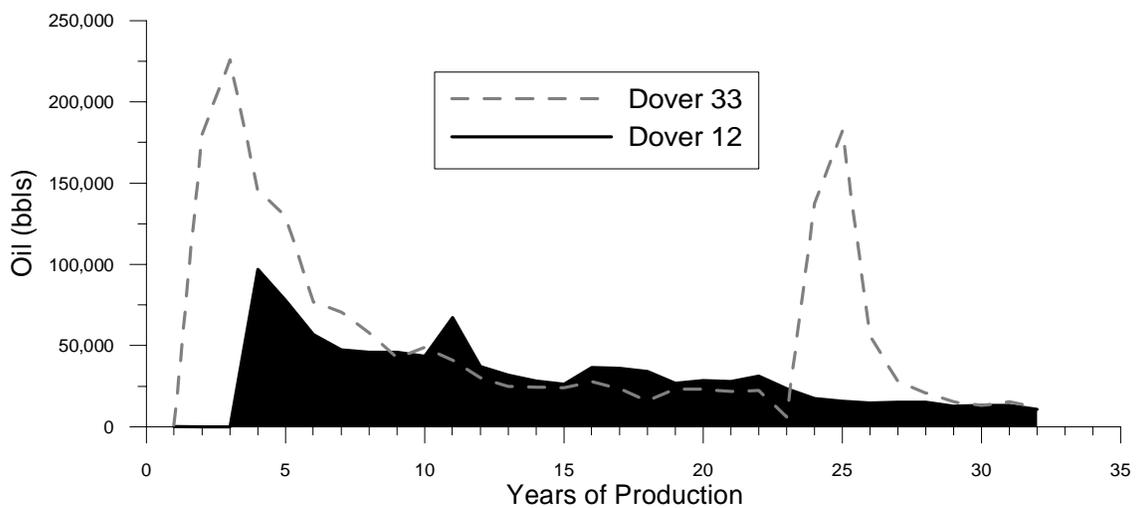
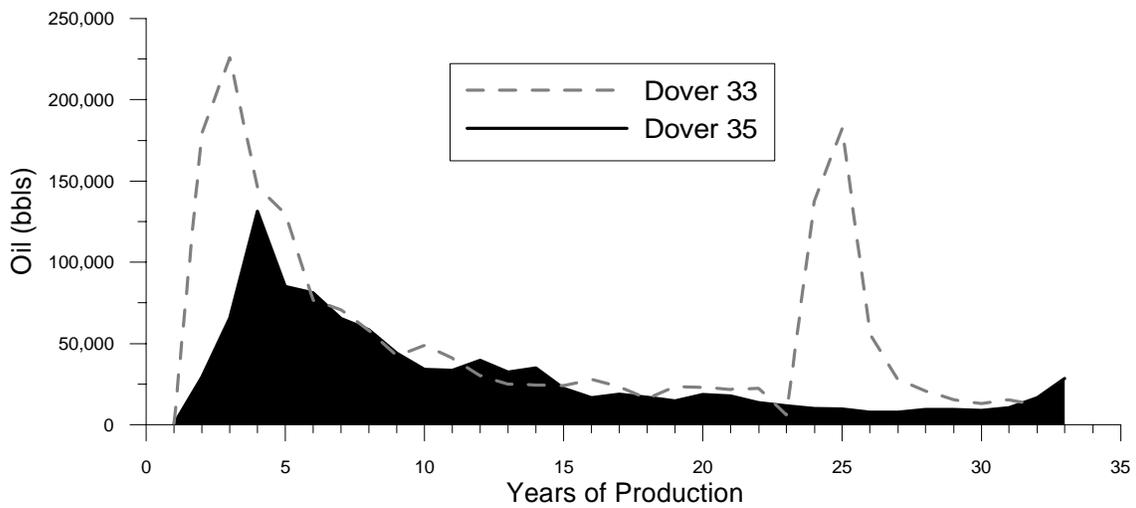
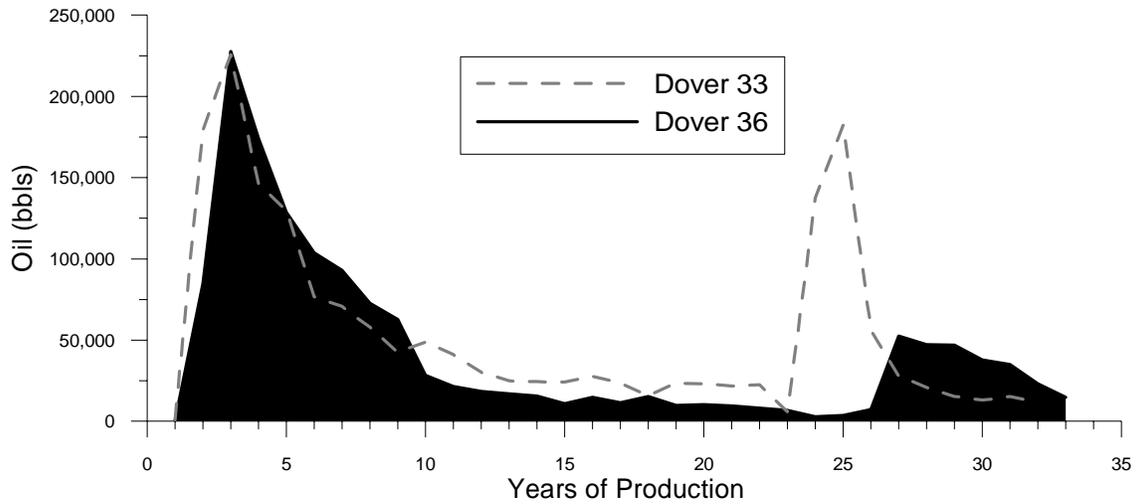


Figure 28. Production curves for the Dover 36, Dover 35, and Dover 12 fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

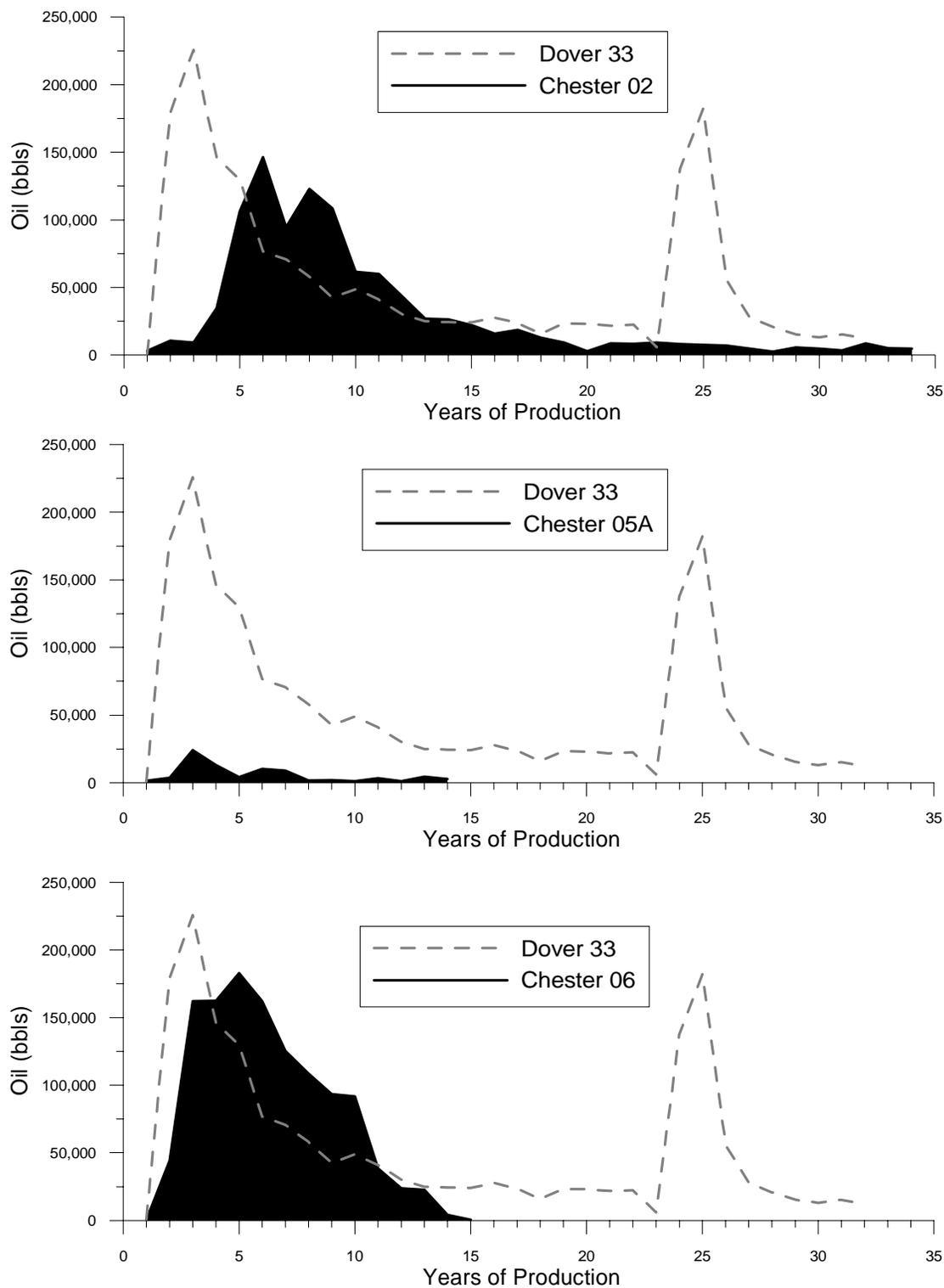


Figure 29. Production curves for the Chester 02, Chester 05A, and Chester 06 fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

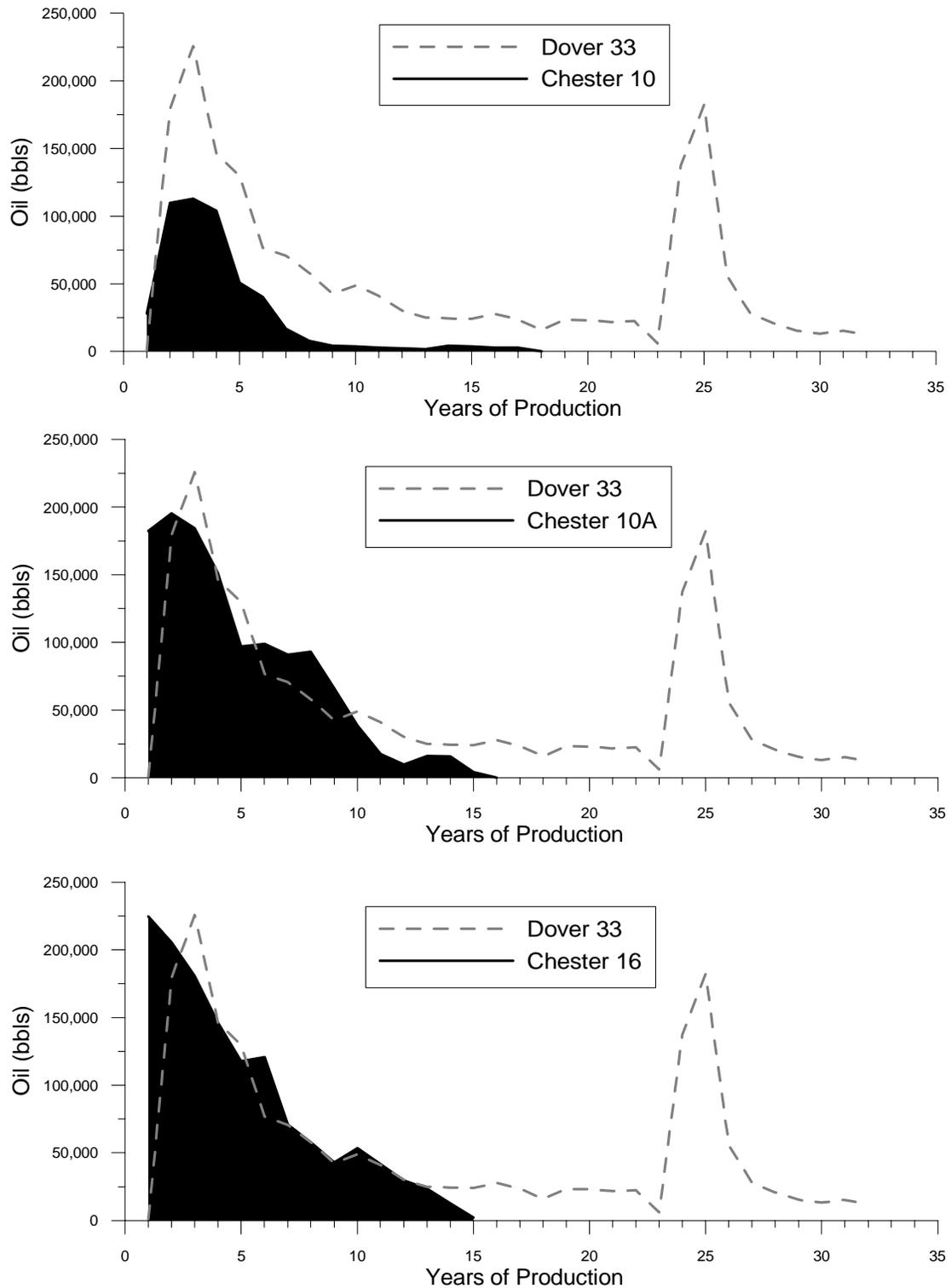


Figure 30. Production curves for the Chester 10, Chester 10A, and Chester 16 fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

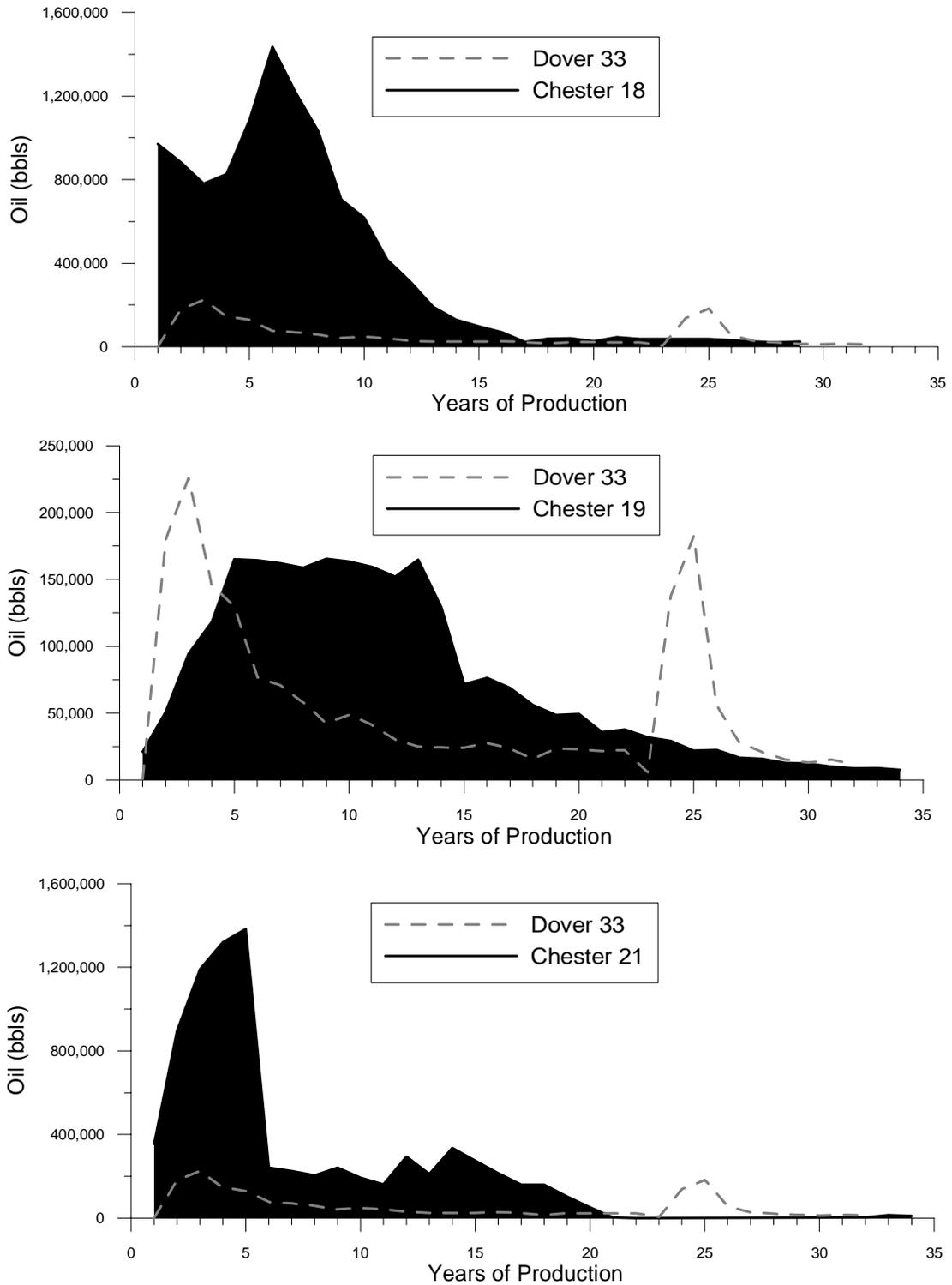


Figure 31. Production curves for the Chester 18, Chester 19, and Chester 21 fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

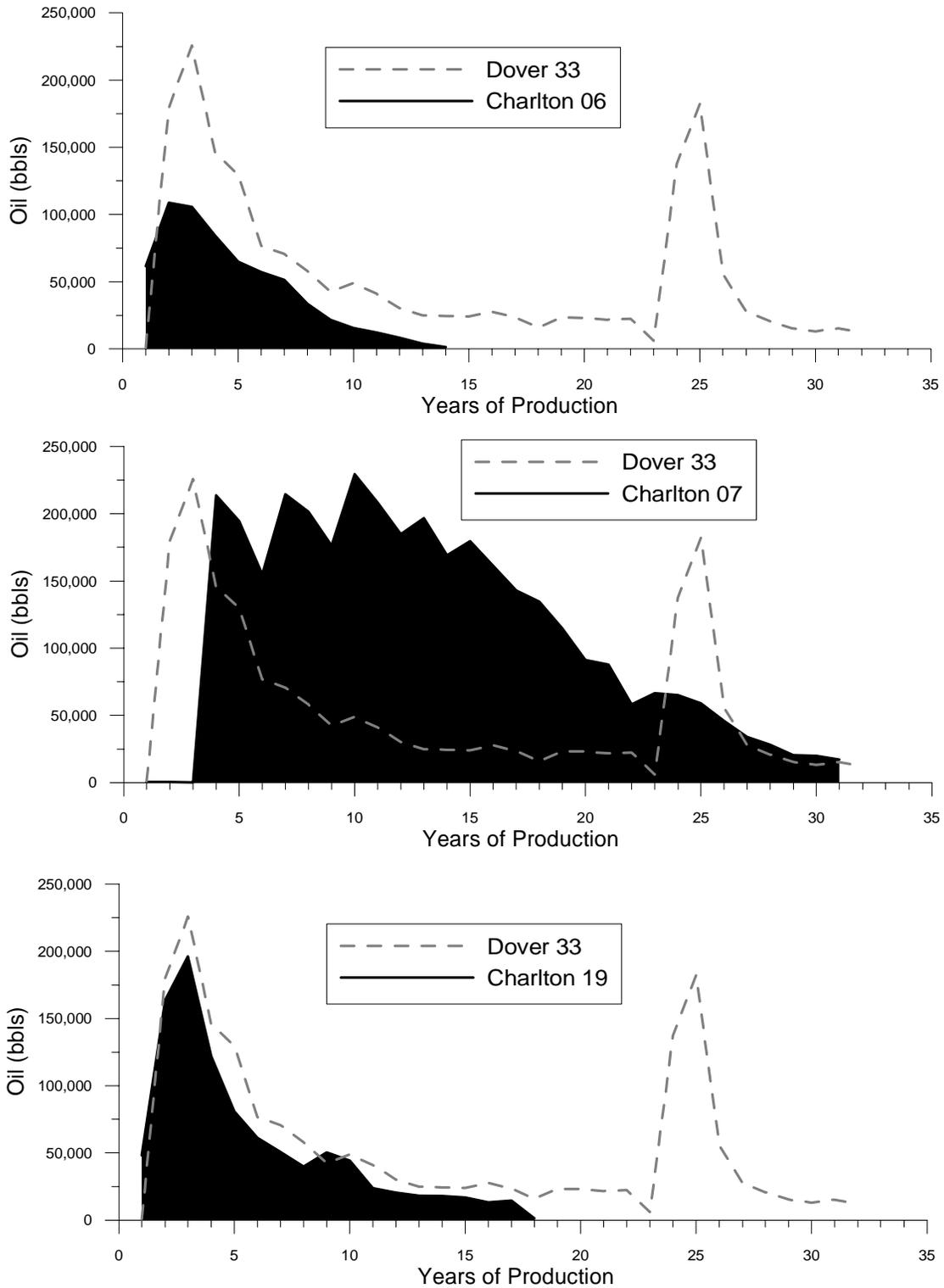


Figure 32. Production curves for the Charlton 06, Charlton 07, and Charlton 19 fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

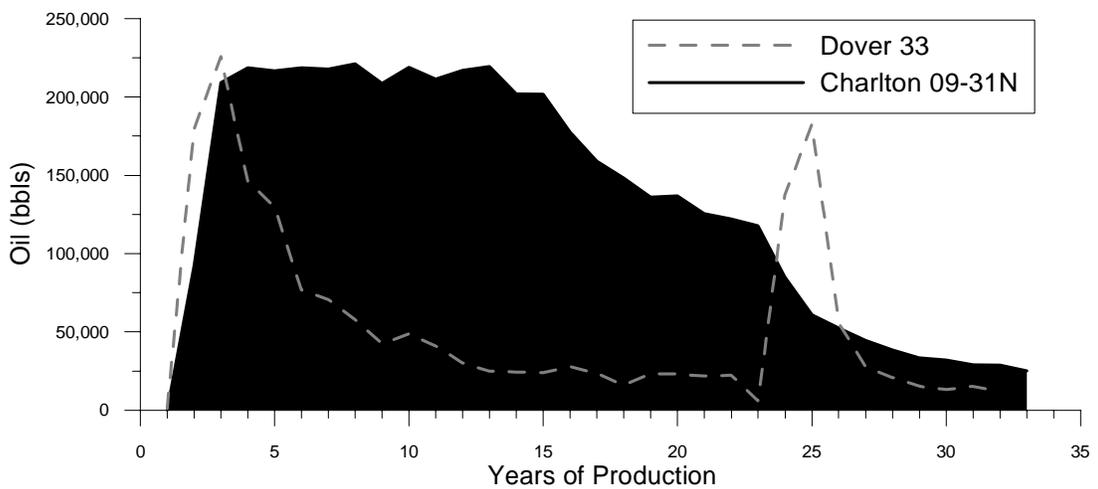
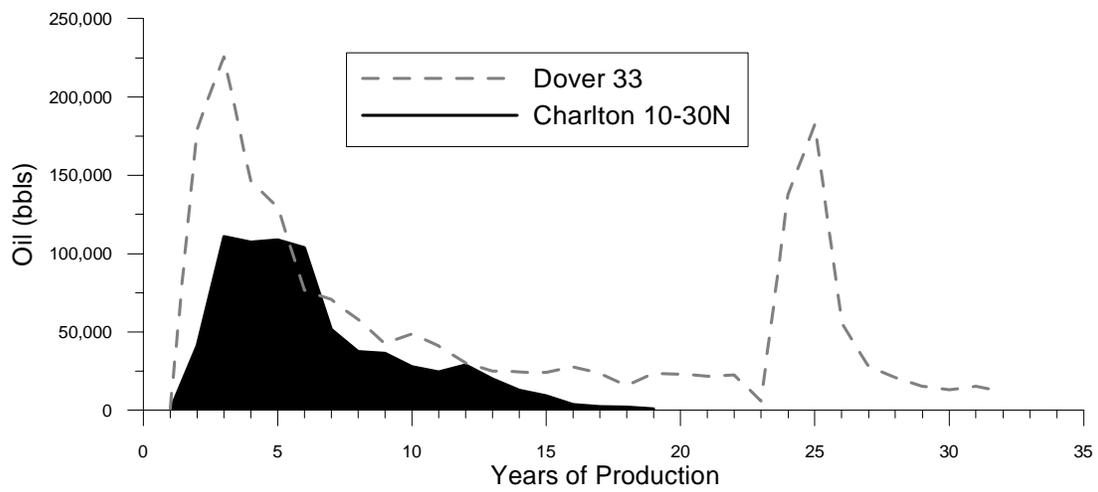
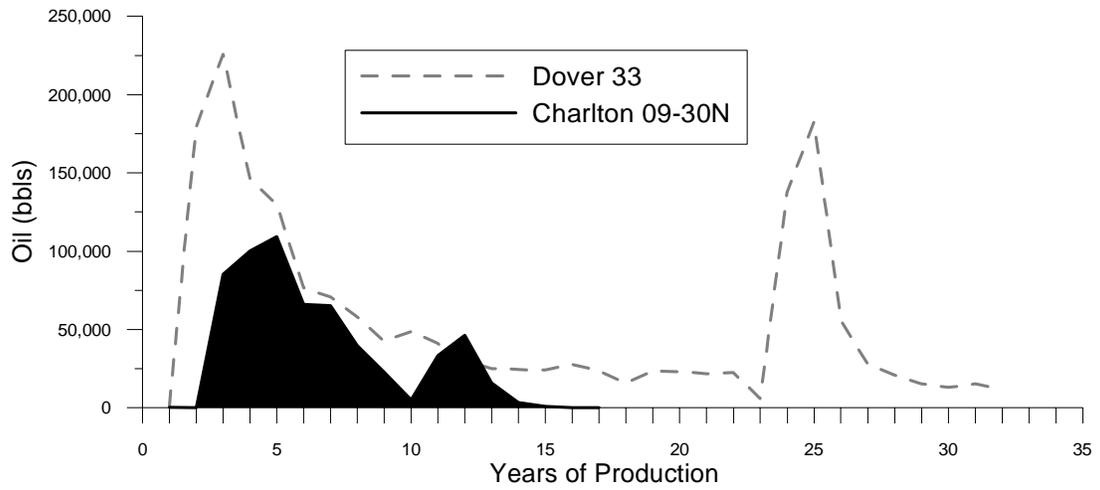


Figure 33. Production curves for the Charlton 09-30N, Charlton 10-30N, and Charlton 09-31N fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

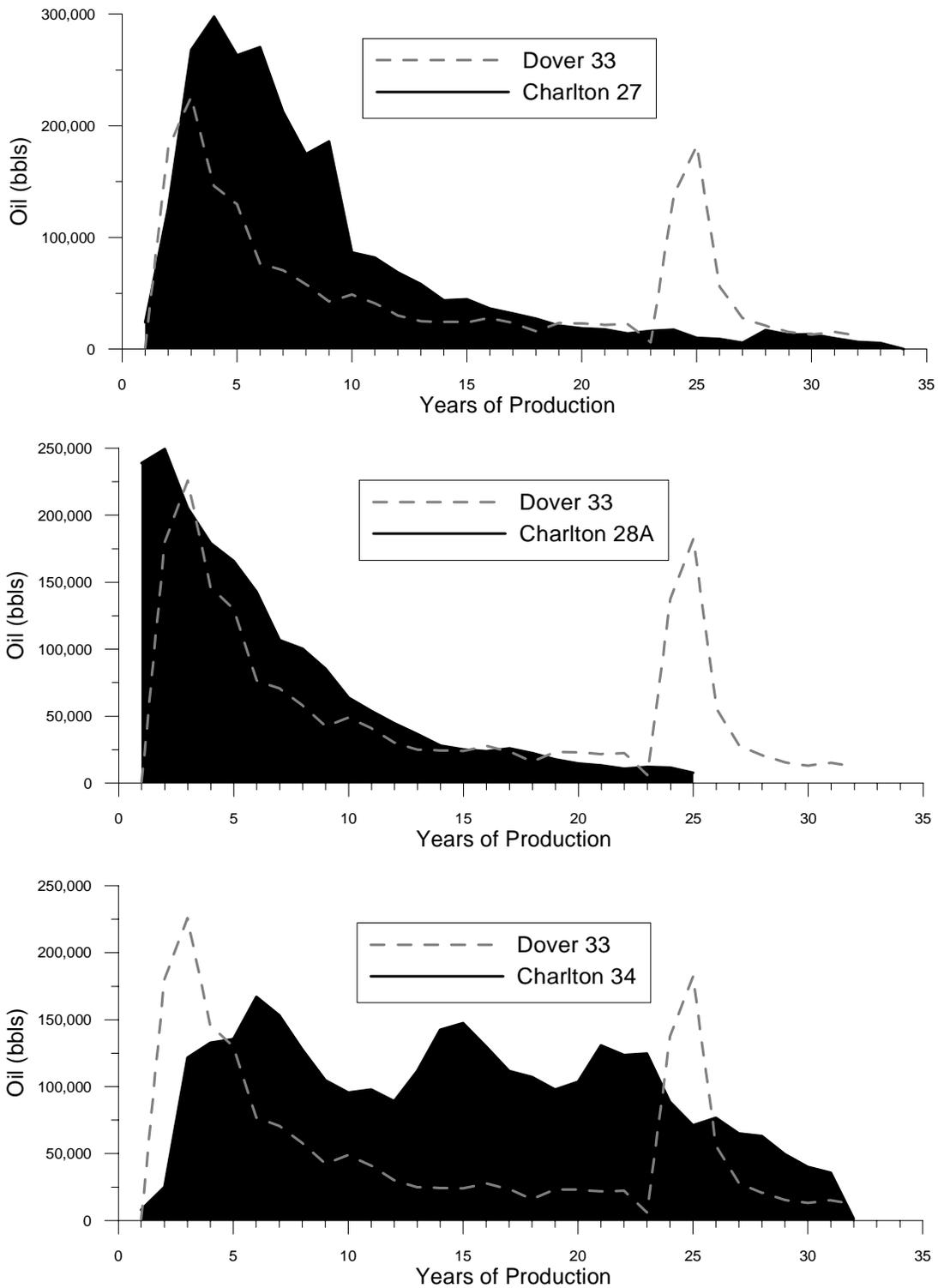


Figure 34. Production curves for the Charlton 27, Charlton 28A, and Charlton 34 fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

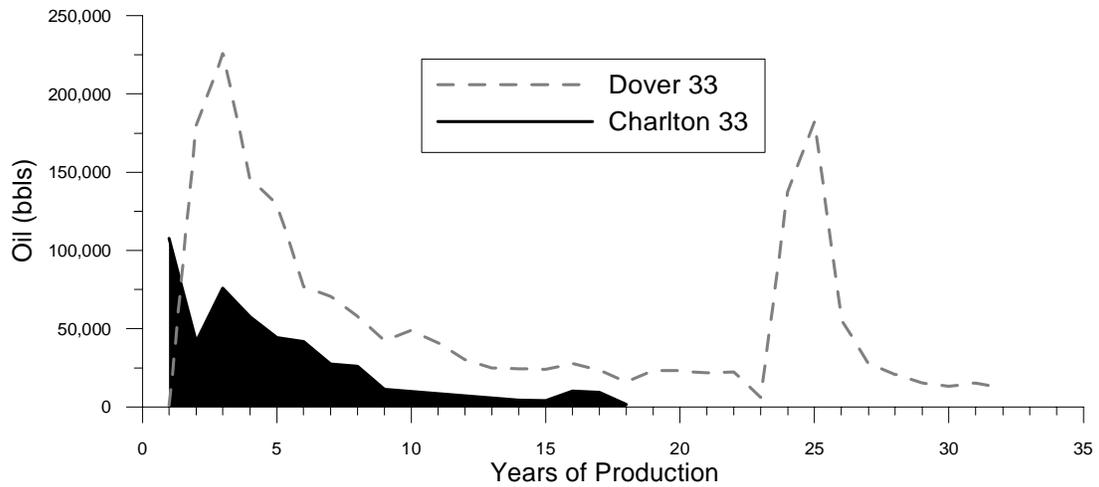
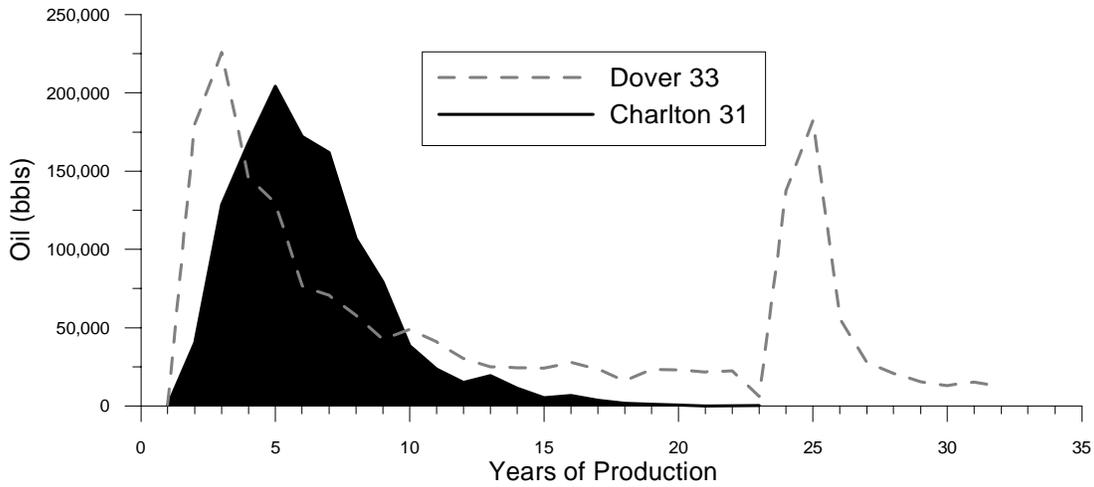
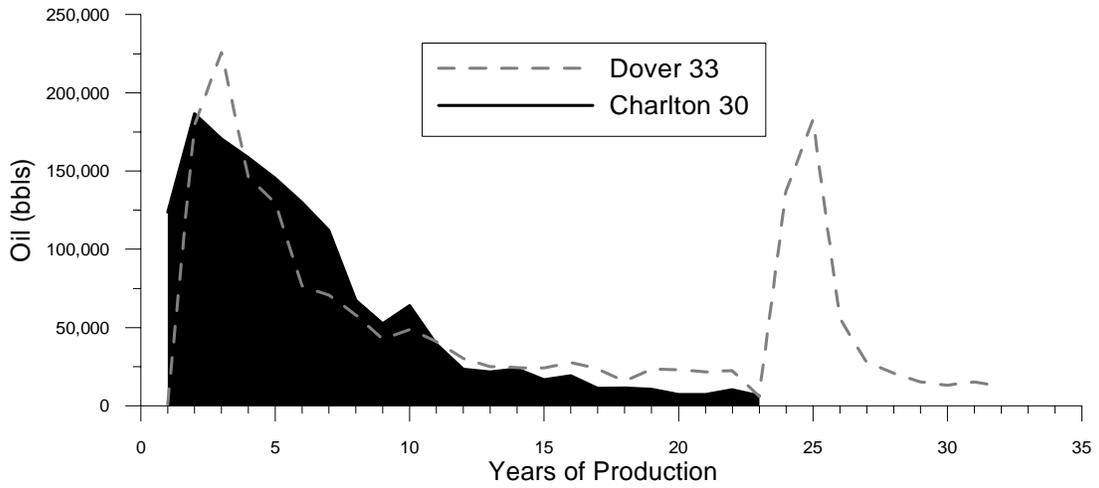


Figure 35. Production curves for the Charlton 30, Charlton 31, and Charlton 33 fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

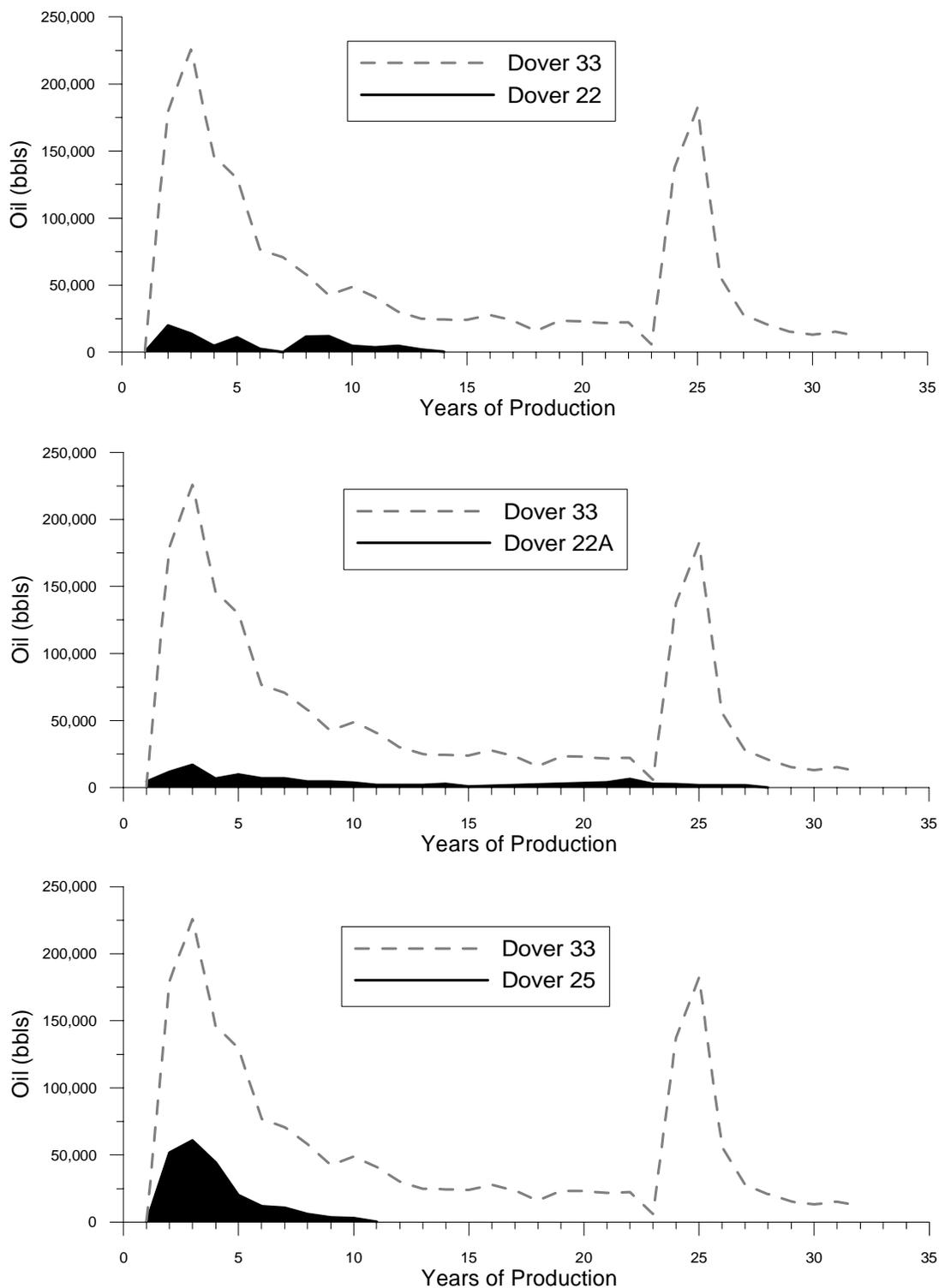


Figure 36. Production curves for the Dover 22, Dover 22A, and Dover25 fields with the Dover 33 production curve superimposed to compare initial production and to predict secondary recovery with CO₂ injection.

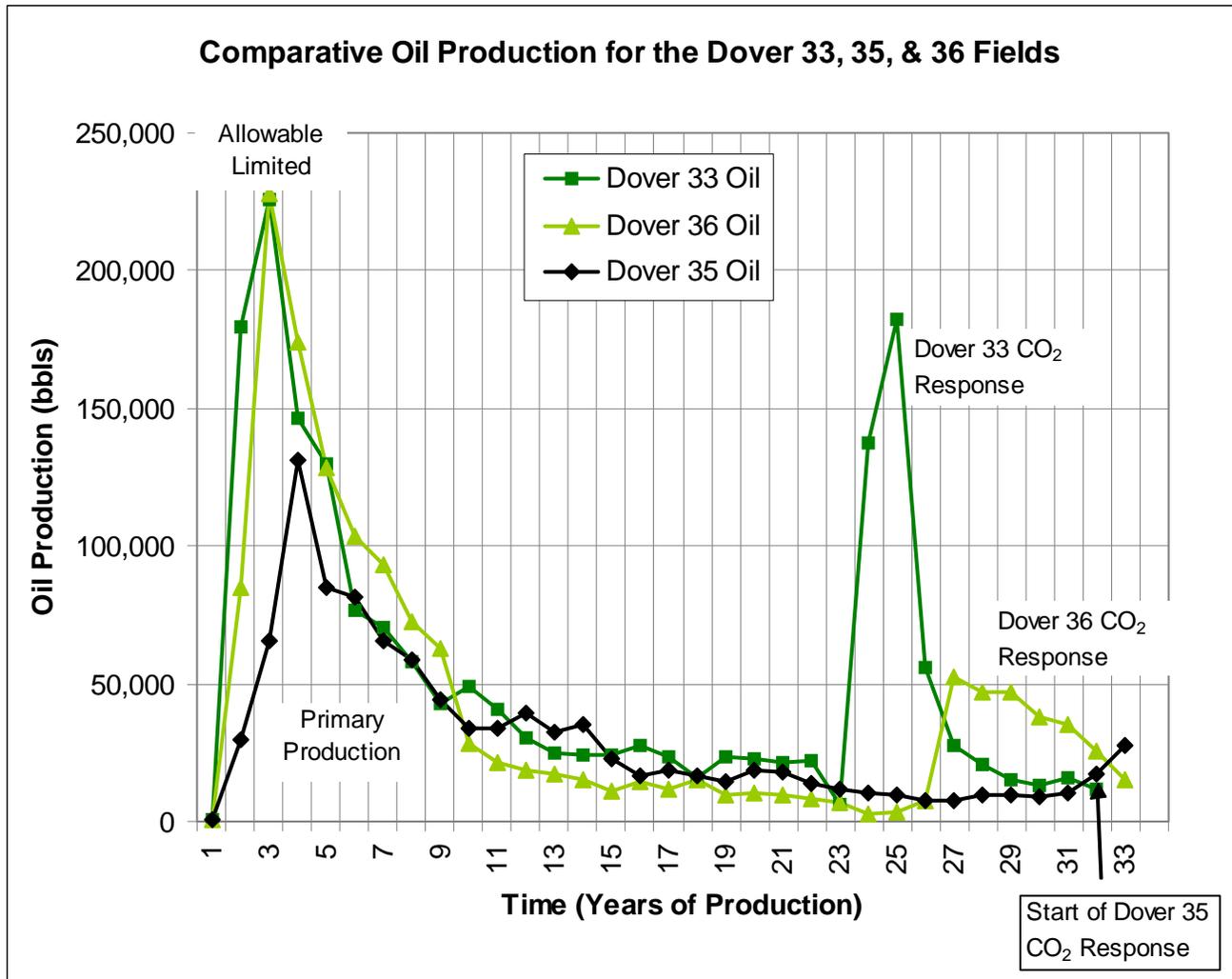


Figure 37. Comparative plot of historical annual oil production for the Dover 33, Dover 36, and Dover 35 fields. Note the similarity in the performance of the three reservoirs during primary production. However, CO₂ injection resulted in significant differences in tertiary recovery—approximately 450 MBO for Dover 33 versus 220 MBO for Dover 36. Dover 35 is still in the beginning stages of tertiary recovery.

Comparative Oil Production & CO₂ Injection

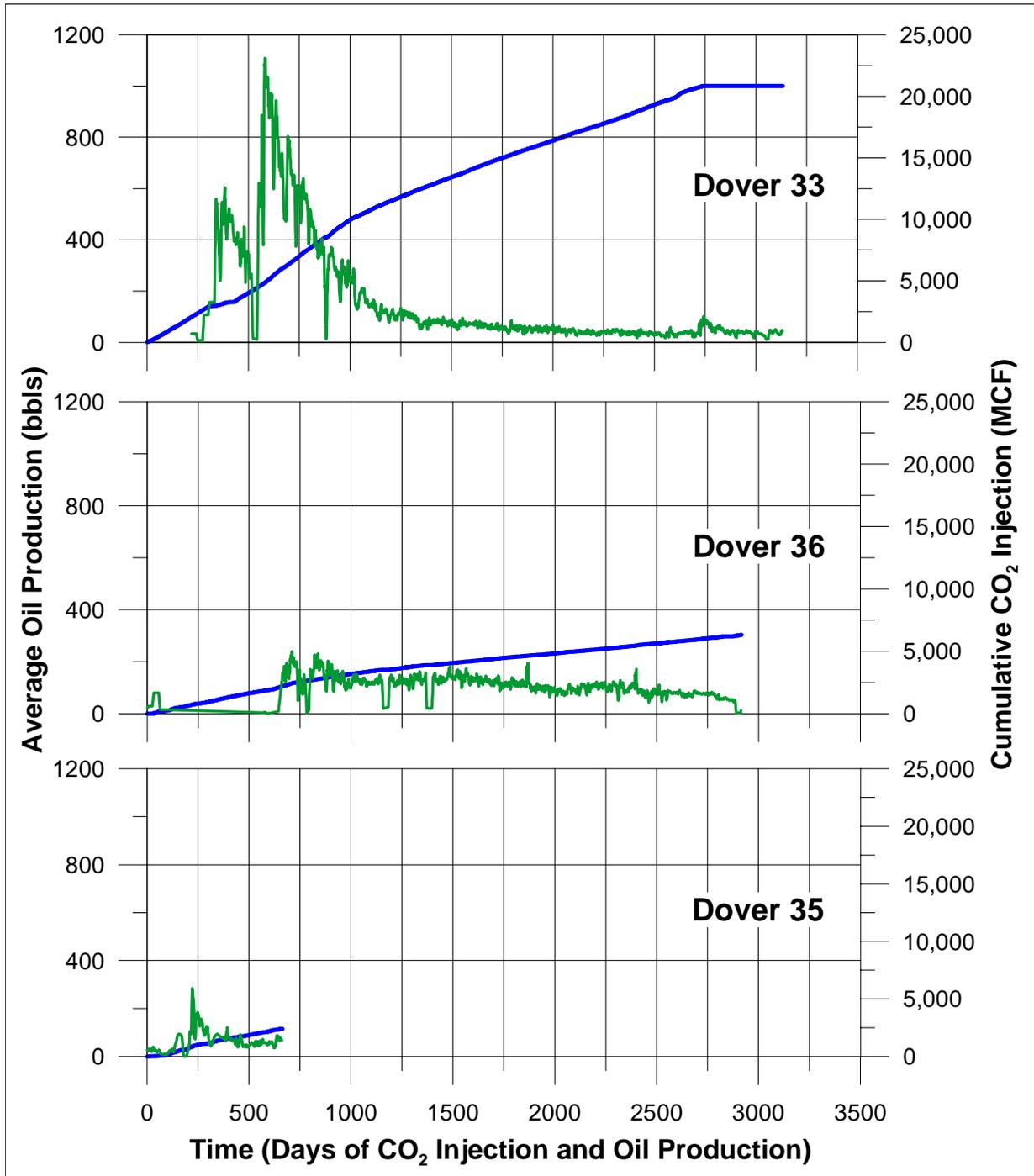


Figure 38. Comparative plot of daily cumulative CO₂ injection and seven-day average oil production for the Dover 33, Dover 36, and Dover 35 fields where the time scale begins on the first day of CO₂ injection for each field. Cumulative CO₂ injection into Dover 33 is 20.5 BCF versus 5.4 BCF for Dover 36. Injection pressures (not shown) were also higher for Dover 36 versus Dover 33 (approximately 1100 psig versus 600 psig).

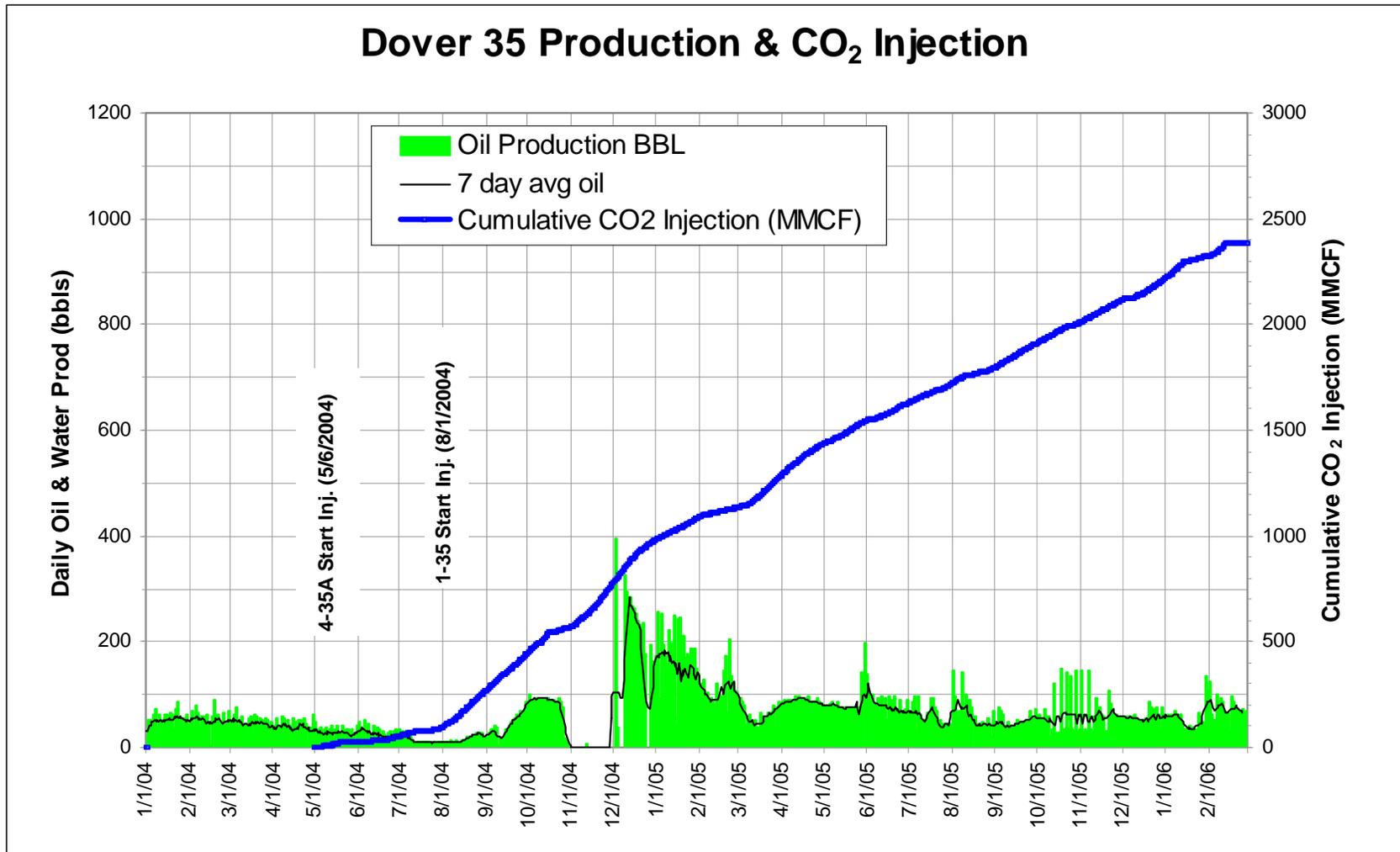


Figure 39. Dover 35 daily oil production and cumulative CO₂ injection. The 1-35 produced approximately 12 BOPD before conversion to injection.