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Colorado School of Mines
Golden, Colorado

**National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma**

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Interdisciplinary Study Of Reservoir Compartments And Heterogeneity

Final Report
October 1, 1993 to December 31, 1996

By
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ABSTRACT

A case study approach using Terry Sandstone production from the Hambert-Aristocrat Field, Weld County, Colorado was used to document the process of integration. One specific project goal is to demonstrate how a multidisciplinary approach can be used to detect reservoir compartmentalization and improve reserve estimates. The final project goal is to derive a general strategy for integration for independent operators. Teamwork is the norm for the petroleum industry where teams of geologists, geophysicists, and petroleum engineers work together to improve profits through a better understanding of reservoir size, compartmentalization, and orientation as well as reservoir flow characteristics. In this manner, integration of data narrows the uncertainty in reserve estimates and enhances reservoir management decisions. The process of integration has proven to be iterative. Integration has helped identify reservoir compartmentalization and reduce the uncertainty in the reserve estimates. This research report documents specific examples of integration and the economic benefits of integration.

EXECUTIVE SUMMARY

This report presents a general strategy for integrating data and people from the disciplines of geology, geophysics, and petroleum engineering. Three key elements for an integrated study are identified. First, the importance of understanding the big picture before going into a detailed analysis. Second, the importance of making the most out of the data that is available and assessing what additional data may help in reducing the uncertainty in the reservoir description. Finally, the importance of estimating the value of integrating the existing data and the potential value of purchasing additional information. This general strategy is summarized in a template for integration.

The economic benefit of integration is demonstrated by specific examples in the Hambert-Aristocrat Field study where a specific project goal is to demonstrate how a multidisciplinary approach can be used to detect reservoir compartmentalization and to improve the reservoir description and reserve estimates. The process of characterizing the reservoir has been iterative.

Integration in the Hambert-Aristocrat field started with sub-regional geologic mapping (over 1000 wells). Studies in the literature, core descriptions, outcrop analogs, and initial producing GOR's were used to define the structural and stratigraphic components of compartmentalization in the sub-regional area. Integration in the focus area of study (approximately 100 wells) included 3-D seismic information, petrophysical data, core permeability measurements, pressure, fluid data, production, and GOR trends. As a result of the integration, the uncertainty in reserve estimates was reduced. In the Hambert-Aristocrat field the net result was an increase in the reserve estimates over estimates made before the integration of data and people. For the detailed study area, the revision in the reserve estimates has an estimated incremental net present value (discounted at 10%) of \$14 million. Thus, integration of people and data in the study area improved the reservoir description, and reduced the uncertainty in the reserve estimates with significant economic benefit.

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INTRODUCTION

The major project objective is to help move small American businesses (oil and gas independent operators) from traditional practices in oil and gas reservoir management to an improved integrated team approach making better use of information and the expertise of people. This objective is being accomplished in two ways: (1) Specific examples resulting from our field study, and (2) A general strategy for integrating data and people from the disciplines of geology, geophysics, and petroleum engineering. This strategy for integration presents a powerful approach for optimizing the economic value of domestic oil and gas resources.

The Lambert-Aristocrat Field in the Denver Julesburg Basin in Colorado was selected to test the methods of integration. The Denver Julesburg Basin, Fig. 1, has been one of the most active in the country and provides an excellent environment to test concepts of integration. Description of a highly compartmentalized Terry sandstone reservoir is the focus of the integrated team approach. The focus area of study is shown in Fig. 2. In compartmentalized reservoirs, wells recover less than expected from a homogenous non-compartmentalized reservoir. In this regard, our field study in the Denver Julesburg Basin will be a model for many other fields in the United States.

The Lambert-Aristocrat Field, discovered in 1972, produces oil and gas from the Cretaceous Terry Sandstone along the east side of the Denver Basin. The Terry Sandstone in the study area produces from a depth of approximately 4500 ft. and there are approximately 100 Terry completions. The reservoir has been interpreted as elongated, discrete, linear bodies deposited in a shoreface environment (Appendix A). Wrench faults in the Denver Basin (Weimer, 1996) have resulted in northeast trending faults with a secondary trend of northwest faults.

A management summary of the integration process supported by specific examples in the Lambert-Aristocrat study area is presented. The details of specific topics are documented in the appendices. The appendices will be referenced frequently in this report. Appendix A documents the geologic aspects of the Lambert-Aristocrat area. Appendix B addresses specific issues related to the 3-D seismic component of the project. Appendix C documents the petrophysical measurements. Appendix D documents the permeability experimental work. Appendix E discusses the well test analysis, production data analysis, and an investigation of well test methods. Appendix F documents the reservoir engineering evaluation done before the full field simulation. Appendix G documents the reservoir simulation component of the project. Finally, Appendix H documents the management strategies investigated in this report and the assumptions in the evaluation of the various alternatives.

A brief discussion of the concept of multiple perspectives and the importance of this concept in integration is presented first. This is followed by a general strategy for integration. The strategy for integration is intended to provide guidance to the small operator in evaluating the potential benefits of integration to improve profits. Examples of integration and multiple perspectives in the study area are documented next. Finally, management strategies, the economic impact of the strategies, and examples of the value of integration are presented.

MULTIPLE PERSPECTIVES

The challenge for independent operators is to know when to integrate and at what level the integration should take place to make the most out of available data. Cycle time for the iterations, another consideration if profits are to be maximized as a result of the integration, are not addressed in this research.

The approach espoused by T.C. Chamberlain (1931) in his classic paper "The Method of Multiple Working Hypotheses" is the challenge for independent oil and gas operators. This paper is based on a presentation made by T.C. Chamberlain in the late 1800's. This paper is significant since it challenges the investigator to consider multiple perspectives rather than using the "Ruling Theory" where we interpret before the facts are known or we hinge our interpretation on a single working hypothesis and force the facts to fit the hypothesis. In practice, application of the concept of multiple perspectives is not easy. When we read the literature (as we should) it is easy to fall into the trap of forcing the facts to fit the current interpretation.

The changes over time in geologic interpretations provide a good example of the importance of integration and the importance of multiple perspectives. Previous interpretations of the Terry Sandstone in our area, for example, describe the reservoir as elongated, discrete linear sand bodies deposited in a marine setting. The structural interpretation was relatively simple with one interpretation describing the reservoir as an anticline (Sonnenberg, 1982). The Denver Basin has been re-interpreted by Weimer (1996) to be dominated by wrench faulting. Current work describes the Terry Sandstone as being deposited in a nearshore environment and compartmentalized by a complex system of northeast trending faults with a secondary northwest trend (Appendix A).

T.C. Chamberlain probably was not thinking about teamwork and integration when he made his presentation. The concept of multiple working hypotheses is a key component to successful integration of people and data. Independent operators need to make the most out of the available data to improve profits. Cost effective integration as demonstrated in this research provides a general strategy for this process.

STRATEGY FOR INTEGRATION

The integrated teamwork on the Hambert-Aristocrat Field study area has identified three key elements for an integrated study: first, the importance of understanding the big picture before going into a detailed analysis; second, the importance of making the most out of the data that is available and assessing what additional data may help in reducing the uncertainty in the reservoir description; and finally, the importance of estimating the value of integrating the existing data and the potential value of purchasing additional information. A brief discussion of this strategy is presented in the following paragraphs.

Big Picture Before Detail

First, an estimate of the overall economic scope of the project should be made. The range of possible values will establish the potential economic benefit of integration and the level of integration warranted. For example, what is the probability that secondary or improved oil recovery methods will be implemented? What is the probability that unitization negotiations will take place? What is the size of your ownership and what is an estimate of the potential value of the resource? Since integration is iterative, the initial boundaries on the level of integration should be altered as needed.

Some data, however, can only be obtained early in the life of a reservoir. This data requires special attention. Two examples are initial pressure and reservoir fluid samples. Pressure data and accurate allocation of production are fundamental to all evaluations. The importance of reservoir fluid samples depends again on the economic scope of the project and the alternatives being investigated. Cores and core descriptions obtained early in the process offer insight into reservoir connectivity or lack of connectivity (compartmentalization). This information is important in evaluating secondary and tertiary recovery projects. Core, petrophysical, and minipermeameter measurements can be used along with production data to reduce the uncertainty in reserve estimates. Again, the economic scope must justify the incremental expenditures where the incremental benefits must exceed the incremental costs. The importance of the cost-benefit analysis is presented in a subsequent section.

The level of detail can be altered as the economic benefits of a refined reservoir description are justified. Doing integration for the sake of integration should be avoided. A complete core description, for example, has value only if it is used to establish a better understanding of the reservoir, and the better understanding can be used to improve profits.

The big picture analysis should identify the key areas of uncertainty, the potential economic benefit of resolving the uncertainty, and the reliability of the information used to resolve the uncertainty. A favorable cost-benefit analysis for integration is paramount. The evaluation team should always ask, given that we are able to resolve the uncertainty, will our development decisions be altered because of the better reservoir description? How much can we afford to pay for a better reservoir description?

The profit improvement can derive from identifying new locations, avoiding dry-hole and completion costs, reducing uncertainty in reserve estimates, improving recovery efficiencies through improved completion practices and well placement, and increasing fair market value.

Make the Most of Available Data

Studies documented in the literature and the performance of analogous fields may provide insight into the performance of a specific reservoir. Commercially available logs, completion, and production data, can be used to prepare sub-regional maps. These sub-regional maps can provide important insight into structural and stratigraphic compartmentalization. When cores are

available, the description can reduce uncertainties in estimating the net pay and determining the sandstone trends. Pressure data coupled to production data are critical to understanding a reservoir and evaluating possible management strategies. Accurate pressure and production data are the cornerstone of the statement "make the most out of available data." Static data provides a starting point. Dynamic data (pressure and production) integrated into the analysis may provide additional support for a hypothesis or may change the interpretation. Making the most of available data means the uncertainty in production estimates due to commingled lease production should be minimized. Frequent well tests can improve the allocation of production commingled at the surface from multiple well leases. When production is commingled at the well bore, the increased cost of obtaining accurate production data is often difficult to justify.

Estimate Value of Integration

It is not always easy to quantify the value of information. Data in isolation from other data may have no value, but when integrated with other data may have significant value. An incremental approach to the analysis should be used. In essence, what is the estimated value of the property with the information? What is the estimated value of the property without the information? The difference in the two cash flow streams is the incremental benefit of the information. This general approach can be used to quantify the maximum amount that can be paid for the information. The maximum value of the information can be established by assuming that the information is perfect. The actual value will be less since most information is imperfect. Probability limit curves (Craig & Thompson, 1994; Craig & Thompson, 1995; Thompson et al., 1996), Fig. 3, can be used to give management a quick look at the probability of success and incremental benefit needed to justify the additional cost of integration. For example, what probability of success is necessary to justify an expenditure for integration if a 10% improvement in Net Present Value profit is required. The decision tree is shown as Fig. 4. Application of normalized probability limit curves aid decision making when the potential benefits and the probability of successful integration are unknown. Figure 5 is a cartoon sketch demonstrating that the incremental benefits should exceed the incremental costs.

General Strategy for Integration

This summary of the integration process provides a general template to improve profits through the integration of data and people. A general strategy is presented in Fig. 6.

1. Define the problem and state the objectives. This analysis includes an estimate of the economic scope of the project.
 - Secondary or improved recovery candidate?
 - Unitization candidate?
 - Large potential for reserves growth?
 - Relatively small equity interest?
2. Identify critical information.
 - Net pay?
 - Reservoir compartmentalization?

- Connectivity - horizontal, vertical.
- Recovery efficiencies?
- Fluid properties?
- Rock properties?
- Flow rates?
- Injectivity?

3. Make the most out of available data. The review of the available data identifies the data that can help with the critical information needs. Not all the available data will be useful. Data should not be used unless it helps meet the stated objectives.

- Pressure data?

- Bottom hole pressures are best.

- Surface pressures are better than no pressure data.

- Fluid levels from shut-in wells.

- Production data?

- Minimize production data uncertainties due to surface allocation on multiwell leases.

- Commercial data?

- Sub-regional maps?

- Seismic data?

- Core and core analysis?

- Core available at public core storage facilities?

Iterative steps (1-3):

The areas of uncertainty are identified in the review of the critical information needs and the available data. Project objectives and scope are reviewed. Critical data needs, if any, are identified. These iterative steps and the possible revision in the economic scope of the project may warrant a change in objectives and the level of resources dedicated to the project.

4. Identify critical data needs and develop criteria for judging value of incremental data.

Data Needs:

- Adequate log suite?

- Better definition of porosity.

- Complete suite of logs early may reduce needs in subsequent wells.

- Fluid samples?

- Pressure transient data?

- Reservoir permeability.

- Completion efficiencies, skin, hydraulic fracture lengths?

- Location of sealing barriers.

- Drainage volumes.

- Seismic data?

- Faults.

- Reservoir quality.

Fluid movement over time.
Core and core analysis?
Special and routine core analysis.

Criteria for assessing the value of the information
Incremental NPV?
Incremental benefits must exceed incremental costs.
Application of probability limit curves?

Iterative steps (1-4):

A cost-benefit analysis of the critical data needs may result in a revision of the economic scope of the project and warrant a change in objectives and the level of resources dedicated to the project. This iteration includes steps 1-3 as the project team balances the estimated costs against the potential benefits.

5. Identify alternatives and develop criteria for comparing the alternatives.

Alternatives:

Horizontal versus vertical completions?
Infill drilling?
Pressure depletion versus pressure maintenance?

Criteria for comparing the alternatives.

Net Present Value?
Payout?
Reduction in uncertainty?

6. Recommendations and plan of action.

FINAL INTERPRETATION

The study area, Fig. 2, includes sections 7-9, 16-21, and 28-33 of T4N 65W and sections 4-6, of T3N 65W, Weld County, Colorado. The Terry Sandstone in the Hambert-Aristocrat area is a low-porosity, low-permeability sandstone. The horizontal continuity is broken by faulting where some of the faults are sealing. Continuous transgressive marine shales that separate shoreface parasequences are probably vertical barriers to flow. The layers near the well bore are likely in vertical communication as a result of hydraulic stimulation. Net pay is difficult to determine because of the high shale content and the thin sandstones. Experimental minipermeameter measurements coupled with the log analysis and production data reduced the uncertainty in estimating net pay. The derived kh map (Appendix C) incorporating the permeability correlation is consistent with the current stratigraphic interpretation in terms of the gradually decreasing reservoir quality to the northeast (paleooffshore direction).

Table 1 summarizes the Estimated Ultimate Recovery (EUR), Estimated Remaining

Reserves (ERR), the cumulative production, and the recovery efficiencies for five producing regions (Fig. 7) in the study area as of January 1, 1995 (1/1/95). Also included in the table is the Net Present Value (NPV) of the ERR for the study using a 10% discount rate.

Several management strategies were tested for the remaining life of the wells in the study area. These management strategies are presented in the management strategies section of this report (Appendix H). Cases that assume a different strategy could take place in the study area commencing with the first well were also tested. These cases are referred to as Time Zero management strategies. These results are also presented in the management section of the report.

INTEGRATION IN THE HAMBERT-ARISTOCRAT STUDY AREA

Two foci of the project were the detection of reservoir compartmentalization and the improvement of reserve estimates early in the life of a field. The following sections present examples from the Hambert-Aristocrat Field study area where integration of data and people were used to support the final interpretation.

Reservoir Compartmentalization

Specific examples that support the current interpretation for the compartmentalization for the Hambert-Aristocrat study area are presented. This discussion is addressed from two perspectives: structural and stratigraphic compartmentalization.

Structural Components

Preliminary structural mapping included a sub-regional picture of structural patterns, Fig. 8. Public data were used to develop these sub-regional maps (over 1000 wells). These early maps provided insight into the Terry Sandstone's structural architecture and the possible role the structure might play in reservoir compartmentalization in the Hambert-Aristocrat study area.

An outcrop from the Upper Cretaceous Mesaverde Group along the Utah-Colorado border near Dinosaur, Colorado, northeastern Uinta Basin was selected as an analog. This outcrop analog has a similar fault pattern to the small-scale faulting which has offset the Terry Sandstone at the Hambert-Aristocrat Field. The sub-regional mapping coupled with an analogous outcrop are important components of early integration. These early "big picture" efforts help identify the structural architecture that can be expected in the Hambert-Aristocrat study area. For this work, the sub-regional investigation highlights the importance of faulting in compartmentalizing the reservoir.

Producing gas-oil ratios (GOR's) were used in conjunction with the structural mapping to aid in the early interpretation of faults, gas-oil contacts (GOC), and possible barriers. Any analysis incorporating GOR's should consider the depths of the perforations, completion methods, and the GOR trends over time. Figure 9 is the final structural interpretation for the study area. The cross section NW-SE, Fig. 10, shows a possible interpretation where the wells on structural highs in a given fault block have higher GOR's than wells lower in the fault block. The sealing

fault interpretations are used to explain how it is possible to have high-GOR wells producing structurally lower than offset wells with relatively lower GOR's. The GOR's used in this analysis were 13th-month GOR's (a snap shot in time).

As noted, the trend in GOR's over time are most important in any interpretation. The GOR trends over time help determine if individual well variability is the result of the structural position of the producing interval, the possibility that the sand has oil with an initial gas cap, the possibility of open layers that include a gas layer, or some combination of these. GOR trends were used to estimate the initial fluid distributions in the study area, and several cross sections were made prior to the reservoir simulation phase of the project. Based on the GOR's of the wells and their trend during the production history, it was concluded that the fluids in the study area were distributed in two main areas: a predominantly oil area and a predominantly gas area, Fig. 11. Individual well fluid contacts need to be internally consistent and should be supported by the reported production history and barrier interpretation.

Seismic data can provide an independent interpretation of the fault patterns and the lithology. The structural interpretation utilizing the P-wave seismic data identified a major northeast-southwest trending fault system, Fig. 12. This fault is part of a fault complex that exhibits a negative flower structure associated with strike-slip faulting in the Denver Basin (Davis, 1985). The S-wave data complemented the P-wave interpretation. In this geophysical data set, only the fault complex shown on Fig. 12 was identified. This fault is referred to as the main diagonal trend fault for future references in this paper. A possible secondary fault system trending northwest-southeast was also identified, Fig. 12. This seismic signature could also be the result of a change in lithology and reservoir quality.

The process of integrating the preliminary geologic and geophysical interpretations with production history provides additional support for sealing faults. Wells 09553 and 09302 in section 29, are separated by the northeast-southwest trending fault defined by the geologic and 3-D seismic interpretation, Fig. 13. Well 09553 is on the south-east side of the fault and produces oil with an average GOR of 2,000 SCF/BBL. Well 09302 is on the north-west side of the fault and produces gas with an average GOR of 100,000 SCF/BBL. The sealing characteristic of this fault is supported by the comparison of the actual production performance and the modeled performance in the reservoir simulator. The fault must be sealing for a good match of actual versus modeled production.

The hypothesis of sealing faults is further supported by the petrophysical analysis. Davis (1985) postulated the faulting in the Denver Basin to be associated with diagenetic events which damage the reservoir quality of the rocks. The petrophysical data from the well 15407 (very low porosity) supports this theory. This well appears to be in a down-dropped fault block in the fault complex described in the geophysical interpretation, Fig. 13. It is postulated that this block has experienced diagenetic cementing which has almost completely eliminated the primary porosity. Another example is in the north-east, in section 20, where well 14079 was completed in 1988 and died very soon after completion, Fig. 13. This well is in the oil region (initial average GOR of 2,000 SCF/BBL). One possible explanation for the short life is the limited drainage area of the well caused by diagenetic cementing which reduced the formation's hydrocarbon storage capacity.

This well is separated from well 14078 (average GOR of 50,000 SCF/BBL since 1988) by the main diagonal trend fault. The presence of calcite cementation in fractures was observed in one core.

Well 15455 was a Terry Sandstone re-entry on 11/1/93. This re-entry was performed after our initial production data gathering effort. In this case, the results of the Terry Sandstone re-entry provide additional support for the location of the main diagonal NE trend fault. This well was designated an oil producer based on early production. The well, Fig. 13, is spotted on the southern side of the main diagonal trend fault. During the reservoir simulation history matching, the oil volume available to this well needed to be increased (fault shifted in the northwesterly direction) to obtain a better match between model production rate and the actual production for the well. The behavior of this well supports the current working hypothesis for the location of the northeast-southwest trending fault and the sealing nature of this fault system.

Finally, a GOR contour map based on the cumulative six-month GOR for the first six months of production for Terry completions (no commingled production) was prepared. This map exhibits a sharp contrast between GOR on the north side of the fault when compared to the south side of the fault trend. A sealing fault along the main diagonal fault trend is one possible explanation for the sharp change in the GOR's. It is important to point out that other interpretations are possible, such as a gas-oil contact. This interpretation adds support for the current hypothesis for a sealing fault system. The two possible interpretations are shown in Fig. 14. It should be noted that this analysis has been simplified by using a snap-shot GOR for wells that commenced production over a several year period.

Stratigraphic Component

Preliminary stratigraphic interpretation is based on the sub-regional mapping using approximately 1000 wells. Again, public data were used to develop these sub-regional maps. The interpretation is augmented by the core analyses of five wells. The sedimentary textures, structures, and stratification sequences were described and facies identified for each of the five cores. The interpretation considers lateral facies changes and regional sequence stratigraphic principles (VanWagoner & Bertram, 1995). Figure 15 is a southwest-northeast stratigraphic cross section. The working model for the Lambert-Aristocrat study area identifies five stratigraphic intervals. These intervals are believed to represent shoreface parasequences which are separated by laterally continuous transgressive marine shales, which have the potential to be significant vertical barriers to fluid flow. Thus, when not faulted, the transgressive shales provide vertical stratigraphic compartmentalization of sandstone bodies. These early maps provided insight into the reservoir compartmentalization in the Lambert-Aristocrat study area.

An alternative interpretation was investigated (Appendix A) which recognizes only three genetic stratigraphic intervals. Using this interpretation it was difficult to explain the landward stepping character of the three genetic stratigraphic intervals. This correlation, based upon log shapes, precludes the possibility of lateral facies changes within the same genetic unit. For these reasons, this interpretation was discarded.

The analogous outcrop is from the Upper Cretaceous Mesaverde Group along the Utah-Colorado border near Dinosaur, Colorado, northeastern Uinta Basin. Comparison of outcrop and core sedimentology and stratigraphy supports the interpretation of long-distance stratigraphic continuity of the shoreface sandstones and transgressive marine shales when not offset by faults identified by the sub-regional mapping.

The description of the cores was further augmented by permeability measurements made on all five cores using a pressure decay permeameter. The permeability data exhibits a relationship between permeability and facies. The permeabilities recorded are absolute permeability to air and have not been adjusted for reservoir conditions. The permeability measurements indicate that the reservoir permeabilities are low, typically less than 2 md. The analysis confirms the suspicion that net pay would be difficult to discriminate from non pay because of the clay content of the sands and the thin sandstones. It is believed that some relatively high permeability streaks exist. This hypothesis is supported by one of the well tests that is hypothesized to be dominated by a high permeability streak. Well tests and production type-curve matches bear out that the permeabilities around the wells are low, on the order of 0.01 to 0.02 md. at reservoir conditions. In dynamic displacement tests a core plug with a permeability of 0.45 md (a "good" quality core plug) reduced to 0.24 md under net reservoir confining stress conditions (absolute permeability to brine).

Sub-regional log analysis work also was used to help understand the characteristics of the Terry Sandstone and how to interpret this shaly sandstone reservoir. Since the Terry Sandstone has very low permeabilities, the mud invasion process is one of slow diffusion of fresh drilling mud filtrate into the formation. The clays hold formation waters near their surfaces and are diluted somewhat by the mud filtrate, leaving a mixture of waters in the flushed zone. The moved hydrocarbon method, bulk volume water versus the bulk volume water in the flushed zone (BWV-BVXO) enhances the ability to detect the laminated sands in most wells (Juhasz, 1981; Schlumberger, 1991; Tixier, 1949; Waxman & Smits, 1968). The technique does not enhance the vertical resolution of the logging tools, but does enhance the ability to detect invasion. In our early work, cutoffs for porosity, water saturation and shale volume were used to define pay. Using the difference between BVW and BVXO as a pay indicator turned out to be a more realistic way to discriminate pay (Appendix C).

The petrophysical analysis, core descriptions, and minipermeameter results were integrated to develop a correlation to estimate permeability from log derived data. This analysis allows the empirical calculation of a permeability index for wells without a core or pressure transient test. Using this correlation, kh maps were prepared for each of the facies. The character of these plots is remarkably similar to the Terry amplitude seismic reflection, Fig. 16. The derived kh map is consistent with the current stratigraphic interpretation in terms of the gradually decreasing reservoir quality to the northeast. The derived permeability relationship provides a beginning point in the simulation as well as guidance in the reserves estimation of individual wells.

During the reservoir simulation history matching, to obtain a match of production performance it was necessary to include production from several unperforated layers which had been interpreted as having been isolated vertically by the transgressive marine shales. This

indicates that the hydraulic stimulation frac jobs were effective in breaking down the vertical barriers (the transgressive marine shales) to fluid flow in some, if not all, of the wells.

Reserve Estimates

Improving reserve estimates early in the life of the field, the second area of focus, requires improving estimates for the values in the volumetric equation. This includes net pay, drainage area, and the recovery factor. Historically, net pay has been a difficult item to estimate. The Terry Sandstone in the Lambert-Aristocrat area is not an exception. Analogy is often used for early estimates of drainage area and the recovery factor. The second stage of improving reserve estimates requires that production performance be coupled with pressure data. These two critical ingredients add insight into the reservoir rock quality, drainage area, and recovery factors. Unfortunately, production often needs to be allocated and pressure data are missing. This is true in the case of this Terry Sandstone study. The following paragraphs give examples where integration was used to improve net pay and drainage area estimates in the study area.

Net Pay

Net pay estimates in the Terry Sandstone were a challenge as the result of clay conductivity, laminar distribution of clays and sands, and the possible effects of light hydrocarbons in the study area. Porosity, water saturation, and shale content were used to make initial net pay estimates using the following cutoffs:

Parameter	Value
Porosity	3%
Water Saturation	55%
Shale Volume Cutoff	40%

In retrospect, these cutoffs appear to give conservative reserve estimates. This hindsight comes from two perspectives: production performance, and the log-core-minipermeability analysis. The first revision was the result of integrating production data. Later in the project when comparing log and core data it was found that the moved hydrocarbons related to the minipermeameter data. The moved hydrocarbon (BVW-BVXO) method was used to discriminate pay zones in the Vern Marshall well and showed that there is much more pay than the traditional cutoffs would indicate (Appendix C).

When using the traditional cutoffs, a well would drain its own spacing plus that of several other nearby producers. When the BVW-BVXO technique is used for discriminating pay, there is an increase in net pay and the volumetric-production picture was much more reasonable. Traditional pay cutoffs that roughly coincide with the BVW-BVXO technique are:

Porosity Cutoff	8%
Water Saturation Cutoff	65%
Shale Volume Cutoff	45%

These revised cutoffs were used to estimate the net pay for the study area. The difference between BVW and BVXO as a pay indicator, as discussed earlier, was not used because of the variability in the quality of some of the logs used to digitize the data. If digitized data had been available, the difference between BVW and BVXO would have been used as a pay indicator.

Drainage Area

Early in the life of a well the drainage area is difficult to estimate. Analogy or well spacing is a common approach. In this study, well control with the aid of producing GOR trends has proven to enhance the structural compartmentalization interpretation. The stratigraphic interpretation and impact on drainage area was enhanced by the integration of core descriptions, log data, and permeability measurements as discussed earlier. Seismic data helped in determining the structural compartmentalization of the reservoir. Also, reservoir quality may be estimated using Vp/Vs information. Unfortunately, the seismic data available did not permit the use of the experimental Vp/Vs information (Appendix B) to discriminate reservoir rock quality (Appendix C). The character of the Terry seismic amplitude reflection did give a measure of reservoir quality on an area basis.

Production type-curve matches made using a production type-curve for Infinite Conductivity Vertical Fractures (Cox, Kuuskraa & Hansen, 1996) provided insight into the drainage area (Appendix E). Since production data is routinely recorded for all wells or leases, this procedure can be used for almost all fields that have a reasonable production history period. The drainage area analysis was hampered by commingled production. In many cases, production is commingled at the well bore (multiple formations) and at the surface (multiple wells).

The pressure transient data was integrated with the geologic and minipermeability analysis to improve production performance predictions. The pressure transient data was used to estimate reservoir rock quality in terms of permeability and hydraulic fracture efficiency (Appendix E).

Reserves Growth

Initial reserve estimates were based on volumetric data and used the best estimate for net pay. As presented earlier, type-curve matches of production data indicated the need to revise upward net pay estimates for individual wells. Further refinement in net pay was made using the integrated results of the core description, minipermeability measurements, and log derived values. Finally, revisions were made during the production history matching phase of the reservoir simulation. The economic benefit of integration (Appendix H) is quantified by comparing the changes in net pay estimates (hydrocarbon thickness) over time.

The ultimate reserve estimates from the simulator were compared with the initial estimates (before integration) and the revised estimates after integration (input to the simulator). The model for the incremental cash flow analysis is presented in Fig. 17. The EUR comparisons for each region of the reservoir are captured in Figs. 18 and 19 for oil and gas, respectively. The

comparison of a cumulative hydrocarbon thickness for each point in time is captured in Fig. 20. Finally, a comparison of the Net Present Value discounted at 10% for the study area is made in Fig. 21.

These comparisons show that the initial reserve estimates are low. The reserve estimates with the integration were consistently higher than the final reserve estimates based on simulation. This may be due to the use of cutoff values for porosity, water saturation, and shale content to mimic the difference between BVW and BVXO as a pay indicator. The hydrocarbon thickness using cutoffs to mimic movable hydrocarbon was greater than the hydrocarbon thickness using the BVW - BVXO method in an example documented in Appendix C. In retrospect, this example appears to be indicative of the field as a whole. Also, it is important to note that these conclusions are specific to the study area. In any given case, the initial reserve estimates may be revised up or down. The value of integration is in reducing the uncertainty in the reserve estimates.

What is the value of reducing the uncertainty in the reserve estimates? The value of reducing the uncertainty in the reserve estimates was quantified through an incremental NPV₁₀ analysis. The incremental value was estimated by comparing the NPV₁₀ of the net operating incomes for the final reserve value with the NPV₁₀ of the estimated net operating incomes from the initial reserve estimate. The drilling and completion costs are assumed to be sunk costs for both cases. In the Hambert-Aristocrat study area, the incremental NPV₁₀ is approximately \$14 million. The estimated cost of integration, \$1 million, has been accounted for in this estimate. The analysis assumes the cost for people and data for the integration of the core, minipermeability measurements, log analysis, and production data as well as the estimated net operating income for a twenty-four month period (Appendix H).

MANAGEMENT STRATEGIES

Several management strategies were investigated. These strategies fall into two categories: first, strategies that could be implemented as of the effective date of our projections (1/1/95); second, strategies that assume that the field could be developed again, but this time using a different development scheme. The first group of strategies will be referred to as the Current Strategies while the second group of strategies will be referred to as the Time Zero Strategies.

For the Current Strategies, baseline economics were established using the reservoir simulator to estimate the future production from 1/1/95 to an economic limit flow rate. Cash flow projections, starting with 1/1/95, were made for each of the cases investigated. These cash flow projections were compared to the baseline case to estimate the incremental benefit of the strategy. For the Time Zero Strategies, baseline economics were established using the reservoir simulator to estimate the production.

There are some management strategies that were investigated or considered but are not listed. Water injection and gas injection, for example, were tested in the simulator but the options were quickly eliminated based on poor fluid injectivity and production performance. Table 2

presents a summary of the economics for the various cases. The follow paragraphs capture the salient points for each strategy.

Current Strategies

1. Perforate layer one in the Terry (Appendix H). No wells generated a positive incremental NPV₁₀ when completed in layer one. Therefore, this strategy was not considered economically viable as an overall field option. This economic projection is based on log derived values for hydrocarbon volume that were input into the reservoir simulator, and an assumed recompletion cost of \$50,000 per well. It is possible that the input to the simulator understates the true potential. However, based on our current estimates, perforating layer one does not add an incremental NPV₁₀.
2. Perforate layer two in the Terry. This strategy generated a positive incremental NPV₁₀ of approximately \$60,000 among three wells. Therefore, this strategy is considered to be viable, but very risky as an overall field option. As with strategy one, this economic projection is based on log derived values for hydrocarbon volume that were input into the reservoir simulator, and an assumed recompletion cost of \$50,000 per well. The three wells with positive incremental gains are located in the buffer region of the reservoir simulator which adds to the uncertainty. Again, it is possible that the input to the simulator overstates the true potential. However, based on our current estimates, perforating layer two does add an incremental NPV₁₀.
3. Infill drilling. This strategy is not considered economically viable. Although one well had a positive incremental NPV₁₀, this prospect is not recommended. The prospect is near a possible fault where the reservoir quality is poor.
4. Fracture or re-fracture wells. Three candidate wells were identified for possible re-fracture treatment. The economics are based on reservoir simulation results that assumed an 100% increase in the PI for each well. The cost for each re-fracture treatment was assumed to be \$33,000. The wells are all located in the buffer region for the reservoir simulation which adds to the uncertainty. The combined incremental NPV₁₀ for these wells is \$360,000. Other fracture treatment variables should be considered before making a final decision.
5. Optimum Current Strategy, perforate layer two and re-fracture. The combined NPV₁₀ for this strategy is \$420,000.

Time Zero Strategies

1. All wells initiated at a common start point. All actual wells studied in our project having a positive NPV₁₀ were assumed to be completed at a common starting point using the reservoir simulator. This approach sets an upper boundary on the value of integration related to optimal well selection. Dry holes and marginal completions were eliminated. This case was compared to the Time Zero baseline economics discounted at 10%. (includes historical production and

ERR from the simulator). When assessing the incremental value of improved well selection, the incremental gain should not exceed \$13.7 million under these assumptions.

2. Horizontal well analysis. The use of horizontal wells to increase the communication with the reservoir and to reduce the number of wells was investigated. An assumed drilling and completion cost of \$500,000 was assigned to each horizontal well. If these three horizontal wells had been drilled replacing fifteen vertical wells, a positive incremental NPV₁₀ of approximately \$700,000 would have been generated. The actual operations, however, would have carried considerable risk. Horizontal wells have not been drilled in this area and therefore the cost assumptions can not be confirmed. Several operators and service companies were contacted for price estimates and provided estimates from \$100,000 to \$1,000,000. Also, an accurate reservoir description would be essential to the success of these wells. In our opinion, an adequate reservoir description would not be available at the time the drilling decision is made. A possible alternative would be an improved seismic interpretation.

CONCLUSIONS

1. Based on the results of this research, a general strategy and template for integration was developed. This template provides guidance for the integration of data and people.
2. Integration of people and data improved the reservoir description in the compartmentalized Terry Sandstone.
3. The economic benefits of integration were quantified:
 - a. Integration reduced the uncertainty in estimating net pay and estimates of ultimate recovery. The incremental benefit of reducing the uncertainty in reserves has an estimated value of \$14 million in the study area.
 - b. Implementing the Current Strategies in the study area has the potential to add a NPV₁₀ of approximately \$ 400,000.
 - c. Horizontal wells may be a viable development alternative for similar reservoirs in the future. An accurate reservoir description would be essential to the success of these wells. Detection of compartments at the time the drilling decision is made would be needed.

RECOMMENDATIONS

The General Strategy for Integration, Fig. 6, provides a powerful approach and way of thinking about problem solving in a multidisciplinary environment. The strategy does not include the words geology, geophysics, or petroleum engineering. Rather, the focus is on problem definition and objectives. Critical information needed to reach the objectives are identified. For example, net pay estimates may be critical for reaching the project objectives. The identified critical information needs lead to data requirements. The economic scope and project objectives

are revised as the available data and the data needs are assessed. The critical information needs are not intended to say for example, "Do a Geologic Study," but rather are intended to focus efforts on the integration of data and people that will answer the critical information needs. Successful integration does away with the compartmentalization of the disciplines and places the focus on getting the best cost-effective solution to the problem. Criteria should be developed to judge the economic viability of purchasing data needs since a cost-benefit analysis is paramount to successful integration. Finally, alternatives should be identified and compared using an economic criteria. The criteria establishes the basis for recommendations and action plans. Similar to T. C. Chamberlain's, "The Method of Multiple Working Hypothesis", the General Strategy for Integration is more than a procedure within which to operate. It is mode of thought when analyzing a multidisciplinary problem. When used, it provides improved results through more effective integration by subordinating a parochial focus to an integrated focus without boundaries.

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APPENDICES

Appendix A - Geologic Report

Appendix B - Geophysical Report

Appendix C - Petrophysical Report

Appendix D - Experimental Data Report

Appendix E - Well test analysis, production data analysis, and an investigation of well test methods Report

Appendix F - Reservoir Engineering Evaluation - Pre-Full Field Simulation Report

Appendix G - Reservoir simulation Report

Appendix H - Management Strategies and Economic Analysis Report

TABLE 1

Summary of Estimated Ultimate Recovery (EUR), Estimated Remaining Reserve (ERR),
Cumulative Production, and Oil and Gas Recovery
Efficiencies on 1/1/95 for the Study Area Wells

The NPV₁₀ is for ERR on 1/1/95

REGION	EUR GAS (MMSCF) / OIL (MSTB)	ERR GAS (MMSCF) / OIL (MSTB)	Cumulative Production (MMSCF /MSTB)	GAS Recovery Efficiency	OIL Recovery Efficiency	NPV ₁₀ ERR
1	17484/93	7858/12	9626/81	65.7%	0.7%	\$ 2,308,288
2	4335/520	2260/97	2075/423	91.2%	13.6%	\$ 1,536,734
3	4882/263	2351/54	2531/209	96.1%	7.2%	\$ 1,231,038
4	11797/474	5729/204	6068/210	77.7%	3.9%	\$ 3,090,818
5	756/101	711/96	45/5	11.5%	5.0%	\$ 651,118
TOTAL STUDY AREA	39254/1391	18909/463	20345/928	67.5%	4.2%	\$ 8,817,996

TABLE 2

Summary of Mangement Strategies
Incremental NPV₁₀

Current Strategies	NPV ₁₀
Perforate Layer One	Negative Incremental NPV
Perforate Layer Two,	\$ 60,000
Infill Drilling	\$ 170,000
Re-Fracture	\$ 360,000
Perforate Layer 2 + Re-Frac Wells.	\$ 420,000
Time Zero Strategies	NPV ₁₀
Common Starting Point	\$ 13,700,000
Horizontal Wells	\$ 700,000

Fig. 1 Location of the Hambert-Aristocrat Field, Colorado (McKinnie, 1993, Atlas of Major Rocky Mountain Gas Reservoirs, New Mexico Bureau of Mines, p. 106).

Fig. 2 Study area including buffer area for resevoir simulaion and area covered by the 3D seismic.

Fig. 3 Probability limit curve for decision to integrate data.

No Additional Integration

EMV Cost without Additional
Integration

NPV Cost Integration

NPV Cost Integration -
Incremental Benefits
from Integration

Probability No Incremental
Benefit

Probability Incremental
Benefit

Incremental Integration

Fig. 4 Decision tree for decision to integrate data.

Fig. 5 Benefits of integration exceeding the costs of integration.

General Strategy for Integration of Data and People

Fig. 6 General strategy for integration.

Fig. 7 Study area showing regions 1-5.

Fig. 8 Sub-regional structure contour map using the D2 Bentonite as a datum.

TOP TERRY STRUCTURE MAP WITH CROSS-SECTION LOCATION

Fig. 9 Final Structure contour map of the Terry Sandstone.

STRUCTURE CROSS-SECTION TOP TERRY SANDSTONE

Fig. 10 Structure cross-section of the top Terry Sandstone. Location of cross-section is shown in Fig. 9.

Fig. 11 Study area showing predominately oil and gas areas.

Possible Northwest-Southeast Fault?

Major Northeast-Southwest Fault

Fig. 12 Amplitude reflection on top of Terry

Fig. 13 Annotated seismic amplitude reflection, top of Terry.

Final Interpretation
Sealing Fault

Alternative
Interpretation
Gas-Oil Contact

Gas

Gas

Oil

Oil

Fig. 14 Comparison of multiple perspectives: Sealing fault versus gas-oil contact.

Fig. 15 Sub-regional stratigraphic cross-section showing five parasequences, A-E study area.

Fig. 16 Permeability-thickness map based on permeability correlation showing trend consistent with stratigraphic interpretation.

NOI with Integration: Integrate Production, Core, Minipermeability

NOI before Integration: Best estimate for EUR's are understated

Incremental NOI for Integration: Incremental Benefit:

Fig. 17 Incremental net cash flow analysis for decision to integrate data to improve reserves estimates.

Fig. 18 Comparison of initial and integrated estimates for oil EUR (bbls) with final best estimate from simulator.

ESTIMATED ULTIMATE RECOVERY - GAS

Fig. 19 Comparison of initial and integrated estimates for gas EUR (Mcf) with final best estimate from

HCFT - PREDICTIONS

Fig. 20 Comparison of initial and integrated estimates for hydrocarbon thickness with final best estimate from simulator.

NPV₁₀ PREDICTIONS

Fig. 21 Comparison of initial and integrated estimates for NPV₁₀ with final best. estimate from simulator.

APPENDIX A

RESERVOIR GEOLOGY OF HAMBERT- ARISTOCRAT FIELD

by

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CHAPTER 1

GENERAL GEOLOGY OF HAMBERT-ARISTOCRAT AREA

Hambert-Aristocrat Field, Colorado produces oil and gas from the Cretaceous Terry Sandstone (alternately referred to as Sussex Sandstone in this area) along the east side of the Denver Basin (Fig. 1-1) at depths of about 4400-4700 ft. (McKinnie, 1993).

As is typically the case in the geologic disciplines, stratigraphic and structural concepts evolve with time and information. Such has been the case for the type of rocks which comprise Hambert-Aristocrat Field, as well as their regional and local structural style. The following discussion highlights the evolution of stratigraphic and structural thought which have led to the knowledge and interpretation of Hambert-Aristocrat Field geology presented in this report. Because the stratigraphic and structural styles identified for the Hambert-Aristocrat field are common, this work has applicability to oil and gas fields far beyond the confines of the Terry Sandstone in the Denver Basin (Slatt and Weimer, 1996)

Regional Stratigraphy

The concept of 'shelf' sandstone reservoirs

The Terry Sandstone in the Denver Basin, as well as many sandstones within the Cretaceous Western Interior Seaway (Fig. 1-2), are elongate, discrete, linear bodies. In the 1970's and 1980's they were traditionally interpreted as having been deposited in an offshore marine setting either as plumes of sand derived from nearby deltas, or as sands reworked into offshore ridge complexes during marine transgression (i.e. 'shelf sandstones', Tillman and Siemers, 1984; Slatt, 1984). Typically, the linear sandstone bodies are encased in shale and comprised of a series of smaller lenticular sandstone bodies, each separated and isolated by shales. Isolation and compartmentalization occur at a variety of scales. Some examples of prolific hydrocarbon producers from what have been referred to as 'shelf' sandstones are summarized below.

The Kuparuk River field, north slope of Alaska, has an estimated 5 billion barrels OOIP, with potential recoverable reserves by routine primary and secondary recovery technologies of 1.6 billion barrels (Gaynor and Scheihing, 1988). The field is divided into a series of isolated, shingled, overlapping sandstones, separated by marine shales. Stratigraphic compartmentalization of productive sandstones has been documented at a variety of scales.

In Alberta, Canada, the Viking Formation produces hydrocarbons from a number of fields (Beaumont, 1984), many of which are also highly compartmentalized and shingled. Also in the Alberta Basin, the Cardium Formation produces hydrocarbons from a number of fields estimated to contain over 2 billion barrels of oil (Leggitt et al, 1990). Pembina is the largest field producing from linear sandstones, with an estimated 1.5 billion barrels of recoverable oil. The presence---though not the detailed internal architecture---of some of these sandstones can be recognized on conventional 2-D seismic records (Slatt et al., 1987), as well as on 3-D seismic (Brown, 1986).

In Wyoming, the Sussex Sandstone is approximately equivalent in age to the Terry Sandstone in Colorado. It produces hydrocarbons from fields such as House Creek (Berg, 1975, Hobson et al. 1982). As of 1980, this field had produced almost 15MMBO and 9BCF from 148 wells. House Creek field is one of many linear sandstones which cover a large geographic area.

Also in the Powder River Basin, the older Cretaceous Shannon Sandstone produces hydrocarbons from more than 26 fields (Tillman and Martinsen, 1985). The largest is Hartzog Draw field which contains 350MMBOIP. Outcrop studies of sandstones that are analogous to those that produce at Hartzog Draw indicate the fields are highly compartmentalized (Hearn, et al., 1983; Tillman and Martinsen, 1984 and 1985; Gaynor and Swift, 1988).

In the Denver Basin of Colorado, near Lambert field, the Singletree, Spindle, and Surrey fields—all considered to be part of the larger Wattenberg field—produce oil and gas from the Terry, as well as from analogous Hygiene sandstones (Moredock and Williams, 1976). A recent summary report by McKinnie (1993) lists Spindle Field Sussex production as 127BCF of gas; the Sussex is formally designated as a Tight Sand.

An example of a linear sandstone reservoir from the Texas Gulf Coast is Kurten Field, which is estimated to contain up to 100MMBO (Turner and Conger, 1984).

Shoreface sandstones

Considerable research in the late-1980's and 1990's, coupled with the acceptance of sequence stratigraphy concepts, has resulted in general agreement that most of the linear sandstones deposited within the Cretaceous Western Interior Seaway are really shoreface deposits (for example, Leggitt, et al., 1990; VanWagoner, et al., 1990; Walker and Eyles, 1991; Pattison and Walker, 1992; Bergman, 1994; Hart and Plint, 1994; and many papers in VanWagoner and Bertram, 1995). Depositional discontinuities that are sometimes overlooked in shelf sandstone interpretations, the lack of a satisfactory explanation for transporting large quantities of sand across muddy paleoshelves then reworking them into ridges, and trace-fossil assemblages have all helped re-evaluate the 'shelf sandstone' model (Bergman, 1994). General models and features of these sandstones are shown in Figs. 1-3 a, b, and c.

Regional Structure

Also in the 1970's and 1980's, the Denver Basin, as well as other Rocky Mountain basins, were considered to be structurally simple, so that many oil and gas fields were thought to produce from stratigraphic traps. More recently, Weimer (1996) has re-interpreted structure in the Denver Basin to be dominated by wrench faulting, which has resulted in a complex pattern of northeast-trending faults with a secondary northwest trend, and associated folds (Figs. 1-4). A similar complex pattern is emerging from detailed work in other Rocky Mountain basins (Martinsen, pers. comm., 1996).

Previous studies of the Terry Sandstone near and in Hambert-Aristocrat Field

Three publications on Terry Sandstone reservoirs near Hambert-Aristocrat Field are important to the present study. They provided important guidelines for the approach to interpreting geology in the Hambert-Aristocrat field.

The first publication is by Siemers and Ristow (1986), who studied the Terry Sandstone in the Antelope field area, north of the Hambert area (Fig. 1-5). They recognized two types of vertical stratigraphic sequences, one which coarsens and thickens upward and another which thins and fines upward. The two types of sequences exhibit distinctive well log patterns (Figs 1-6a, and 1-6b). Interpretation of a few hundred well logs revealed that the coarsening/thickening upward sequence occurs as a northwest-trending linear sandstone body which lies to the northeast of the more areally-extensive fining/thinning upward sequence (Figs. 1-7a, and b). The fining/thinning upward sequence is oil-productive in the area, while the coarsening/thickening upward sequence contains non-productive gas. As was typical of interpretation in the 1980's, Siemers and Ristow claimed that the coarsening/thickening upward sandstone body is an offshore shelf sand ridge. This ridge created a channel-like depression on its landward side into which sands were deposited from southeasterly-flowing shelf currents, to give a fining/thinning upward sequence there.

The second study is of Latham Bar Trend, which produces oil and gas from the Terry Sandstone about 5 mi. to the northeast of Hambert-Aristocrat field in T4/3N, R65/64W (Al-Raisi et al., 1996) (Fig. 1-5). Latham Bar Trend is an elongate northwest-trending sandstone body (Fig. 1-8). Over 500 permeability measurements of the four facies comprising the sandstone, using a pressure-decay permeameter housed in the Colorado School of Mines' (CSM) Petroleum Engineering Department, reveal a strong facies control on permeability, even though permeabilities are low, in the range 1-10md. (Fig. 1-9).

A structure map compiled using a bentonite bed (prominent log marker) beneath the sandstone as a datum reveals the presence of numerous northeast trending faults (Fig. 1-8). Figure 1-10 is a schematic depiction of the nature of interpreted fault blocks along the length of the Trend. Pressure data were not available to evaluate whether these fault blocks comprise separate reservoir compartments isolated by sealing faults, so two other criteria were used to evaluate them: (1) distribution of 13th production-month GOR among wells in the area (13th month was chosen as a basis for standardization and comparison of GOR's from all the wells along the Trend) and (2) distribution of EUR among the wells. A map of GOR's (Fig. 1-11) reveals that different fault blocks exhibit significantly different GOR's. Listing of GOR's along the schematic cross-section of Fig. 1-10 shows that standardized GOR's increase progressively up-structure within individual blocks. A map plot of EUR across the Trend exhibits considerable scatter, but when EUR is plotted against thickness of the main reservoir facies within any fault block, a linear relationship is revealed (Fig. 1-12). These distributions together strongly suggest that individual blocks are compartmentalized in Latham Bar Trend and that bounding faults are sealing to fluid flow (Al-Raisi, et al., 1996)

The third study is a structural interpretation of Hambert Field by Davis (1985). He indicated a northeast-trending set of listric normal faults across Hambert Field based upon conventional 2-D seismic data (Fig. 1-13). Prior structural interpretation had shown a relatively simple northwest-trending anticline (Fig. 1-14) (Sonnenberg, 1982).

Two additional studies are worth mentioning. Porter and Weimer (1982) interpreted the Terry Sandstone in the Spindle Field area as offshore shelf bars. They recognized four phases of diagenesis. Phases 1 and 2 were early compaction and formation of authigenic chlorite rims, silica overgrowths, and calcite cement. Phases 3 and 4 were later calcite solution to form secondary porosity followed by partial occlusion of the secondary porosity by authigenic kaolinite and minor illite. Pittman (1988) expanded upon Porter and Weimer's (1982) work by determining that half of the pore volume in reservoir sandstones is microporosity associated with clay minerals and lithic fragments. Pittman found ductile deformation of lithic fragments to be a major factor in porosity loss in the sandstones. He identified chlorite and calcite as the major mineral cements, with minor to trace amounts of authigenic quartz, dolomite, ferroan calcite, kaolinite, feldspar, pyrite, and tourmaline.

CHAPTER 2

CONSTRUCTION OF GEOLOGIC DATABASE IN HAMBERT-ARISTOCRAT AREA

Objective

The Hambert-Aristocrat Field and adjacent area chosen for study encompasses 70 Sections--(within T3N-R65W, T4N-R65W, T4N-R66W) (Fig. 2-1). Almost 2000 wells have been drilled (Fig. 2-2) providing the opportunity to thoroughly evaluate the sub-regional to local stratigraphic and structural geology of the field and surrounding area. **Experience (further substantiated in this study) has demonstrated that structural and stratigraphic characterization of a field should not be confined to just the area of the field, but should be based upon somewhat more regional to sub-regional structural and stratigraphic patterns.**

During the course of this research, a methodology was developed for downloading and formatting the large data set that was available. In most U.S. petroliferous basins, many wells have been drilled, providing the potential for application of large databases for further exploration and infill field development. Determining the degree of complexity of an oil or gas reservoir is best accomplished by integrating widely diverse geologic, engineering, and geophysical data, such as are available in the Hambert-Aristocrat area. Though time consuming and sometimes difficult, the reward can be improved reservoir management, leading to more production dollars.

However, small to mid-sized companies without computer-intensive staff would normally have difficulty in utilizing large data sets because of the expertise and time required to search and locate well data, then download and manipulate it into useable format. Thus, we describe below, in detail, the methodology we developed for this project to build and manage a large database in the PC computing environment, since this computing environment is most common amongst small and mid-size independent oil and gas producers.

Hierarchy of database development

The process described below uses four main phases, or hierarchical levels of activity (Fig. 2-3). In order of increasing complexity, they are:

- (1) **Compilation:** identifying the sources of data.
- (2) **Extraction:** gathering, organizing, and storing data in a manner that allows easy access.
- (3) **Interpretation:** processing, describing, translating, comparing, contrasting, classifying, correlating, and calculating data.
- (4) **Analysis:** interpretation and synthesis of data into general and specific characterizations that attempt to explain the facts and observations.

As shown in Fig. 2-3, there are many tasks, sub-tasks and iterations from the Compilation through Analysis phases. Fundamentally however, the process defines nothing more than a series of information flows (i.e. the results of one task are used in the next). This process is highly non-linear, and information frequently flows in loops, often more than once. The Compilation and

Extraction phases used to develop the large well data base for this project are discussed below. Interpretation and Analysis are discussed in subsequent chapters.

Basic well information

The basic well and production data used in this study were derived from Dwight's well history and production CD-ROMs. These data were first downloaded into Microsoft EXCEL for WINDOWS spreadsheets so as to facilitate flexible data selection and sorting criteria.

The first step in the process was to extract selected historical well data for all wells in the study area (Fig. 2-2). Within this area there is a total of 1974 unique "completions" (a given well or surface location may have more than one unique completion). Each unique completion is assigned a unique number by Dwight's called the "RECORD NUMBER". This is the basis for linking the various pieces of extracted data. From these wells, the following records were extracted:

HEADER	Basic Well Information
TOPS	Formation Tops
COR	Core Data
DST	DST Data
PPI	Perforation Data, Perforation Zone, and Initial Potential Data
LL	Latitude and Longitude

These data were extracted into "comma delimited format" files for import into EXCEL. In the comma delimited format, each field on the output record is separated by a comma, allowing for easier parsing into the EXCEL spreadsheet. Ideally, each unique completion should have only one line in any of these output files. However, only the HEADER and LL data files were constructed in this manner. They were imported into EXCEL spreadsheets without difficulty. Each unique completion had two or more lines in the PPI TOPS, COR, and DST files. Because of the number of records that were extracted, the TOPS, COR, and DST information was easy to clean up and import into EXCEL files. However, because of the volume of data in the PPI file, this information was extracted from the Dwight's database and broken into three separate files. Along with the completion data, the permit and completion records were extracted and labelled as follows:

PER	Perforation Data
PZO	Perforation Zone Information
IP	Initial Potential Data
CMP	Permit & Completion Data, including Dates

As extracted, each file had limited usefulness. They needed to be cross correlated between each other, certain data fields needed to be in each file, and some data files were of no use to this project.

The first data that was analyzed was the Tops data. As extracted from Dwight's, the comma delimited file consisted of one line per record number and formation top. This data was summarized into an EXCEL spreadsheet called TOPSDATA.XLS (Table 2-1). This file contains a list of all tops recorded from all wells in the area, with each formation name on a single line. This file also contains the number of occurrences of each top, minimum and maximum depths, and average depth.

The next data group was the completion and IP data. The PERFS, PERFSZONE, and IP XLS files were combined into a single file called COMPDATA.XLS (Table 2-2). The data from the perfzone information consisted of as many as four lines of data per record (single completion). Thus, the first step in cleaning up this file was to create a single line of information from the multiple lines. Additional columns were created to accommodate the data on one line. The same was true for the data from the perfs and IP files. Multiple lines were reduced to a single line per record. Up to this point the perfs, perfzone, and IP data were treated separately, although all data items were in the same file. When the perfzone and perf data was compared, it was discovered that the perfzone information was redundant. Therefore, it was eliminated from the file. The remaining IP and perf data were aligned by record number. The data fields in the final version of COMPDATA.XLS are shown in Table 2-2.

The next group of data is the basic well information. Specific data fields from the HEADER, LL, and CMP files were combined. Since there was not a single case of multiple lines per record, combining this information was rather straightforward. The data was combined into a file called HEADER.XLS (Table 2-3). Columns called OWWO and SSXPROD were added to the header data file. The OWWO data field indicates duplicate API numbers and the SSXPROD data field is a flag that indicates if a particular well is or was a Terry test. The data fields LAT, LONG, API, OWWO, SSXPROD, and RECNO from the header data file are duplicated in the COMPDATA.XLS file (Table 2-2). This assures that each and every record in either file has a corresponding record in the other file.

Once the basic files were constructed, the next step was to quality check certain key data fields. It was obvious that not every record in the COMPDATA file contains the proper initial potential data. In the Dwight's database, the majority of the initial potential information is in a data field called IP COMMENTS rather than in the individual data fields (Table 2-2). This information was extracted into a text file and imported into EXCEL. Organizing this information was much more complicated than the completion data had been before. In this case, there are as many as eight lines of information per record number. Fortunately, there are identifying data fields in the files that allow the comments to be grouped together. As before, all information for a single record number was aligned onto a single line. Additional columns were added to accommodate this information. This file is called IPTEXT.XLS (Table 2-4).

The production data must be handled differently from well history data because in Colorado production is recorded on a lease basis, rather than on a single well basis. Without contacting Operators, there is no easy way to correlate production data to well history data. There is an API number listed within the production data. This number represents the key well for the lease and it may be used to correlate the production data to a single well. Location, lease name, and

sometimes intuition must be used to identify all the wells on a particular lease. Even if all the wells on a particular lease can be identified, there is no way to proportion the production among the various wells. However, by knowing which wells are on which lease, the lease GOR data can be plotted at any or all wells on the lease. The main problem with this is that lease designations are artificial and may not follow natural geologic or reservoir boundaries.

The production summary data was downloaded from the Dwight's CD-ROM into comma delimited files. These files were imported into an EXCEL file called PRODSUM.XLS. Some of the data fields in this file are:

Data field	Contents	Data Field	Contents	Data Field	Contents
FIELD	Field and Reservoir	LOCATION	TWP-RNG-SEC	LEASE	Lease & Well Number
OPER		Current	API	API	STATUS
Status	Operator		Number		
GOR	Gas-Oil Ratio	LIQCUM	Cumulative Liquid Volume	GASCUM	Cumulative Gas Volume
LAST		Last Month	LAST	Last Month	
MOOIL	Oil Prod.	MOGAS	Gas Prod.		

Following this procedure, all the basic data for all wells in the field are found in one or more of the following files:

TOPS.XLS	(Table 2-1)	Formation Tops
COMPDATA.XLS	(Table 2-2)	Completion information
HEADER.XLS	(Table 2-3)	Basic well information
IPTEXT.XLS	(Table 2-4)	Initial Potential Information
PRODSUM.XLS		Summarized Production Data

GOR Data

As discussed in a later chapter, GOR data are considered critical to evaluating the degree of structural complexity and compartmentalization of the Terry Sandstone in Hambert-Aristocrat Field. The source of the GOR data was the Dwight's production and historical data CD-ROM. Since many wells may exhibit erratic early production behavior, we 'normalized' GOR values. Normalized GOR's were calculated in two ways, as shown below.

$$13\text{GOR} = \frac{\text{Volume of Gas produced in the 13th month}}{\text{Volume of Oil produced in the 13th month}}$$

$$\text{Average GOR (AGOR)} = \frac{\text{Volume of gas produced in months 1-12}}{\text{Volume of Oil produced in months 1-12}} / (12)$$

The advantage of the 13 GOR is that it represents the GOR for each well in the same way (i.e. normalizes) and it removes all erratic early production from the calculation. The disadvantage is that, in any given well, it is possible that the 13th month may not be normal in terms of production. The well may have exhibited mechanical difficulty and may have been off-line for a period of time. If the well was a gas well, and if the 13th month occurred during summer, it may have been throttled back due to lack of a market. The AGOR "smoothes" the erratic production resulting from these reasons. The AGOR however, is influenced by any erratic, early well behavior.

There are two problems in obtaining this type of data. First, the only GOR record in the Dwight's database is the initial GOR. The second problem is that Dwight's front end only allows the user to extract production data for absolute time periods (such as all production in 1991), but since each well was completed at a different time, this method did not suit our purpose. The solution was to download all monthly production data for all Terry wells into an EXCEL spreadsheet and to write code that would identify and extract only the production data from the first 13 months of production. This spreadsheet also calculated the 13GOR and the AGOR. By having it in a spreadsheet format, this information could be combined with the other information in databases built previously. There are 147 leases that produce from the Terry Sandstone in Hambert-Aristocrat field.

The resultant data were organized such that each lease is on a separate line in a file called GORALL.XLS (Table 2-5). Both the 13GOR and the AVGGOR are listed.

API Gravity Data

Liquid gravity data were also cataloged. The best source for this data is the IPTEXT file (Table 2-4). EXCEL code was written to search for and extract the liquid gravity and the initial potential GOR as well.

Core Data

Basic information on cored wells in the area was input into a file named COREDATA.XLS (Table 2-6).

Summary Data File

A summary file was created, named SSXDATA.XLS, which contains all Terry related records from the COMPDATA (Table 2-2), HEADER (Table 2-3), IPTEXT (Table 2-4), and GORALL (Table 2-5) files (Table 2-7a,b). This 78-column file is the basic product for recording and tracking Terry well data for the geologic part of this project.

Tops Data File

Based on a first-pass stratigraphic analysis of well data (discussed in a later section), seven horizons were initially identified on well logs and assigned a letter designation (Fig. 2-4). From top to bottom they are:

"A"	Top of the Sussex Interval
"E"	Upper Marker
"B"	Top of the Sussex Sand
"G"	Top of Basal Sussex Sand
"C"	Base of the Sussex Sand
"D"	Upper Bentonite (actually, two bentonites---labelled D1 and D2--- are present in some areas)
"F"	Lower Bentonite

Data input forms were created in EXCEL. These forms contain basic well identification information such as operator, lease, and well number as well as space to record the depths of the seven horizons. We compared the log elevation on Headers to the elevation recorded in the database, and recorded comments when necessary.

These data allowed calculation and input into an EXCEL spreadsheet of subsea depths of horizons and horizon isopachs. All of these data are in a file called INPUT.XLS (Table 2-8a and 2-8b).

Logs that were examined are from the CSM collection and from the Denver Earth Resource Library (DERL). All logs in the CSM collection and selected logs from DERL were printed. The tops that were recorded were input into an EXCEL spreadsheet. A summary of the horizon tops data set generated is listed below:

Number of wells in the area of interest compiled: 1975

	Elevations		Frequency
	Low	High	
Database Elevation	4616	4745	1144 of 1149
Log Elevations	4678	5043	335 were different
Corrected Elevations	4675	5050	1146 of 1149
Elevation Difference	-3000	+100	833 had no difference

Subsea Elevations by Horizon

Horizon	Low	High	Freq.
A	253	615	938
E	238	590	603
B	164	555	940
G	216	372	125
C	117	499	940
D	89	470	904
F	63	314	440

942 wells out of 1149 had at least one top picked. 85 wells do not have latitudes or longitudes. A total of 799 wells were printed, which are on file at Colorado School of Mines.

Analyzing anomalous or erroneous Tops data

In a project of this size, it is reasonable to expect that errors resulting from transcription, typographical and data entry will enter into the Tops database. These errors can be identified and eliminated in several ways. Code was written in the spreadsheet to search for bad data. For example, if the log depth value for the "A" horizon was greater than the value of the "B" horizon (Fig. 2-4), we could conclude that there is an error in either "A" or "B". The data of each horizon, each isopach, and the elevation data can be sorted and wells with the extreme highs and lows can be noted and re-examined to see if the data are erroneous. This information can also be plotted on frequency histograms. The frequency histogram for the "A" horizon (Top Terry) is shown in Fig. 2-5 (first pass). Based on this histogram, it appears that this horizon occurs mainly within a structural elevation range of 360-472 ft. a.s.l. Any wells with values outside this range should be examined for error.

Isopach data can be treated in the same manner. A frequency histogram for the isopach between horizons "A" and "B" (middle sand) is shown in Fig. 2-6. The bimodal nature of these data may indicate that the correlation of either "A" or "B" has not been consistent over the entire area. The best way to evaluate this inconsistency is by first locating the geographic area in which the anomalous data are located, then constructing regional stratigraphic cross sections to evaluate whether there are any Tops mis-picks. In our analysis, the cross sections verified that there was indeed a correlation problem and that horizon "B" was frequently correlated erroneously with horizon "G" (Fig. 2-4) on the northeast side of the study area.

Once all the Tops had been verified (the second pass), erroneous Tops were corrected and entered into the EXCEL spreadsheet and a new set of histograms was constructed. For example, the new histogram of the top of the "A" horizon has anomalously low and high values removed (Fig. 2-5) and the isopach between horizons "A" and "B" no longer exhibits bimodality (Fig. 2-6).

Even after two passes through the database, we found many wells with Tops that are anomalous, i.e. in the upper and lower 1% of the histograms (the histogram tails). There are several reasons other than erroneous data that may result in a well exhibiting anomalous data. These include:

(1) bad kelly bushing elevations (if a bad elevation was suspected, it was compared to a topographic map).

(2) deviated wells which cause both structure and isopach data to appear as anomalies on histograms (if a well was known to be deviated through the Terry interval, it was eliminated from our database).

(3) miscorrelations, as mentioned above.

(4) geologic faults, discussed below.

Use of data files for mapping

Although the methodology described above is time-consuming, once the database is built, and purged of any well data deemed to be erroneous, it is possible to quickly generate multiple iterations of maps. These maps have many uses. For example, they can be used as a final quality check for anomalous or erroneous data, which will appear as 'sinkholes' or 'pinnacles' on the maps (Figs. 2-7).

The most important map is a data distribution base map which shows the location of all wells in the area. For example, we plotted a map with the API number alongside each well (for identification) and a three letter code which showed if the well had been examined for tops, if a print of the log had been made, and if the well is a Terry producer.

Subsea and isopach maps can also be easily generated by downloading data in the EXCEL tops spreadsheet into an ASCII file. We generated sample maps using the MCSTM (Mapping Contouring System) program. Such preliminary computer-generated maps did clearly highlight wells with bad data and provided a general configuration of the structural and stratigraphic variability over the area, including locations of major faults (for example the trend of 'sinkholes' in Figs. 2-7).

However, there are problems associated with computer-generated contour maps. They are inherently unreliable because they cannot be contoured with a geologic concept in mind; this issue is discussed in more detail in a following section. Never-the-less, computer-generated maps are useful in providing generalities of structural and stratigraphic trends as well as in identifying erroneous well information.

CHAPTER 3

STRUCTURE OF HAMBERT-ARISTOCRAT FIELD

Sub-regional structure

A sub-regional structure contour map of the Hambert-Aristocrat and adjacent areas, using the D2 Bentonite beneath the Terry Sandstone as datum, is shown in Fig. 3-1. This map reveals the same structural complexities in the area as revealed by Weimer's (1996) structure map of the entire Denver Basin (Fig. 1-4), so a similar wrench-fault interpretation is favored.

This map was derived using D2 Bentonite tops from the INPUT.XLS file (Table 2-8a). An original computer-generated structure contour map revealed no meaningful geologic pattern, so the final map shown in Fig. 3-1 was hand-contoured with Weimer's (1996) geologic trends in mind. GOR data, discussed below, provided a secondary guide to mapping. A northwest-oriented structural cross section of the D2 Bentonite and overlying Terry Sandstone is shown in Fig. 3-2.

Regional structural dip is gently toward the northwest (Fig. 3-1). In the northwest, Bentonite elevations are generally at 240-280 ft. a.s.l., while toward the southeast they are in the range 280-320 ft. a.s.l. Local variations are a result of the intense faulting and folding in the area (Figs. 3-1 and 3-2).

The dominant fault trend is northeast, with a secondary northwest trend. The amount of lateral offset on wrench faults has not been possible to determine, but it was determined that these faults do have vertical offset. Fault cuts through the Terry Sandstone were interpreted in 46 wells in our database (2.3% of total wells), but it is very likely that there are more small faults. Fault cutouts range from 10 to 160 ft. Repeat sections were not observed, indicating the vertical component of faulting is normal rather than reverse. Also, because of the abundance of well Tops data, it was possible to map folds within individual fault blocks (Figs. 3-1 and 3-2).

The sense of motion on Denver Basin wrench faults is thought to be right lateral (Weimer, pers. comm., 1996). These faults are thought to have developed over pre-existing basement shear zones that were reactivated during the Laramide Orogeny. The compressive forces that uplifted the Rockies were translated into lateral slip in the Denver Basin. Considering compressive stress directions, the fault patterns mapped in Fig. 3-1 are reasonable. Some of the small structural lows and highs mapped in the area might represent 'pull-apart' grabens and 'pop-up' blocks, respectively, which accomodate changes in the volume of rock as it is deformed by shearing.

Local structure within Hambert-Aristocrat Field

For the purposes of developing a structural model for Simulation of the immediate area of Hambert-Aristocrat Field, a structure contour map was desired using the datum within, rather than beneath the Terry Sandstone (i.e. the D2 Bentonite; Fig. 3-2). Some Cretaceous sandstones within the Western Interior Basin have been mapped as climbing stratigraphically toward the west.

If true for the Terry Sandstone in Hambert-Aristocrat Field, structure contour maps using sandstone datums, rather than a bentonite datum (Fig. 3-1) would exhibit a false structural climb toward the west. To test for this effect, a computer-generated isopach map was constructed for the interval between the top Terry ("A") and D2 Bentonite, using the data in INPUT.XLS (Table 2-8a). There was no significant variation in thickness across the study area, indicating the Terry Sandstone does not climb up section.

A first-pass structure contour map (Fig. 3-3) and corresponding structure cross section (Fig. 3-4) were completed using the middle or "B" sandstone top (Fig. 2-4) data in the INPUT.XLS file (Table 2-8a). This map and cross section show the dominant northeast trend of faults and a series of tilted fault blocks similar to those depicted on Fig. 1-10 for Latham Bar Trend to the northeast.

Because of difficulties (discussed in a later chapter) in correlating sandstone packages within the Terry interval, a second structure contour map (Fig. 3-5) and cross section (Fig. 3-6) were completed using the Top Terry ("A" sandstone) datum (Fig. 2-11) from the INPUT.XLS file (Table 2-8a). This Top was found to be consistent and easier to pick across the area. The structure contour map shows a similar pattern of complex faults and folds, as does the corresponding northwest-southeast structural cross section (Fig. 3-6).

A 3-D seismic horizon slice in sections 29, 20, and 17 (discussed in more detail elsewhere in this report) confirmed the presence of some, but not all of the faults.

It should be pointed out that the positions and orientations of faults are not precisely the same in all three structure contour iterations. Offsets are generally greater than can be accounted for by having been constructed on different horizons. Each iteration was completed by a different geologist, thus illustrating human variability in map construction and placement of faults.

CHAPTER 4

PRIMARY RELATION OF STRUCTURE TO GOR'S IN INDIVIDUAL WELLS

Distribution of GOR's

In the Lambert-Aristocrat Field, GOR's of individual wells exhibit the same relation to structural trends as was the case in Latham Bar Trend (Figs. 1-10 and 1-11). GOR values have been plotted on three structure contour maps (Figs. 3-1, 3-3, and 3-5), as well as on the three structural cross sections (Figs. 3-2, 3-4, and 3-6). Examination of the cross sections, for example, illustrates that in almost all cases, GOR values increase with structural elevation a.s.l. within an individual fault block.

Gas-oil contacts have been interpreted on Fig. 3-6 on the basis of depths of perforated zones and GOR values. For example, wells #7533 and #8670 exhibit low GOR's, so the gas-oil contact is probably well above the perforated interval. Well #15071 has a somewhat higher GOR, so the perforated zone probably straddles the gas-oil contact. Well #9302 exhibits a very high GOR, so the perforated zone is probably well above the gas-oil contact.

Within the Denver Basin, as well as other Rocky Mountain basins, a common problem has been the anomalous distribution of oil and gas wells producing within a given formation. For example, an oil well might occur structurally higher than an adjacent gas well in close proximity. If GOR's for individual wells were plotted on any of the three structure contour maps (Figs. 3-1, 3-3, and 3-5) without considering faults and fault block configurations, there would be no apparent pattern to their areal distribution. When such configurations are considered, however, the areal distributions of about 90% of GOR's can be explained.

Not only has this relationship been established for the Lambert-Aristocrat field in this project, but Muddy (J) Sandstone reservoirs in the Denver Basin beneath Denver International Airport exhibit the same relation between GOR and structure (Fig. 4-1).

Sealing faults and reservoir compartments

The above relations between structure and GOR suggest that the faults are sealing to the cross-boundary flow of reservoir fluids. Unfortunately there are no pressure data from which to confirm or refute this hypothesis.

In addition to the above relations, one other line of evidence does support a sealing fault interpretation. Most density logs in the area exhibit a computed density of about 2.5g/cc (Fig. 4-2). However, one well (#15407; Fig. 4-3) exhibits an anomalously high density of >2.6g/cc. This well plots on a fault on the Top Terry structure contour map (Fig. 3-5), suggesting that a fault cuts the well and the fault may be sealed with higher density material such as calcite cement. Evidence in support of this hypothesis is the presence of radial calcite (?) cement filling a 45° fracture in the General Oil No. 1 Eckhardt core (at 4429.4ft.; Fig. 4-4), discussed below.

Sandstones very near this fracture exhibit permeabilities of $<0.5\text{md}$, whereas the same facies just above and below exhibit permeabilities of $1\text{-}2\text{md}$.

CHAPTER 5

STRATIGRAPHY AND SEDIMENTOLOGY

Regional stratigraphy

As previously discussed, Siemers and Ristow (1986) found the Terry Sandstone north of Hambert-Aristocrat Field to exhibit a change in log stratigraphy from blocky or fining/thinning upward in the west to coarsening/thickening upward toward the east. The same pattern occurs in the Hambert-Aristocrat study area (Fig. 5-1). In fact, a relatively distinct boundary between the two patterns is mappable across the study area (Fig. 5-2a) which lies along the same trend as that mapped by Siemers and Ristow (1986) (Figs. 1-7a, and b). However, we feel that the explanation provided by Siemers and Ristow (1986) is too simplistic for the Terry Sandstone in the Hambert-Aristocrat area, perhaps as well as in the area they described.

An initial attempt at regional stratigraphic correlation revealed that the stratigraphy is complex and that several genetic stratigraphic intervals are present across the area. An early correlation scheme recognized three genetic stratigraphic intervals, termed Upper, Middle, and Lower (Fig. 5-2b) (Edington, et al., 1994). Correlations were based more or less on log shapes. Tops for these three intervals were input into INPUT.XLS (Table 2-8a) and maps were computer-generated (Fig. 5-2c). Although the distribution of the Upper, Middle, and Lower intervals is possible, it doesn't consider lateral facies changes within the same genetic unit and within a sequence stratigraphic framework. For these reasons, this initial correlation scheme was discarded for that described below. **However, it is worth pointing out the value of multiple attempts at stratigraphic correlation, and that more than one correlation scheme is possible for a stratigraphic interval.**

A second attempt at stratigraphic correlation resulted in a scheme that considers lateral facies changes and regional sequence stratigraphic principles depicted in Figs. 1-3 a,b, and c. A southwest-northeast oriented stratigraphic cross section is illustrated in Fig. 5-3. Five stratigraphic intervals are identified and are labelled A-E. These intervals are considered to represent shoreface parasequences (Fig. 1-3 a,b, and c). Parasequences B, C, D, and E are separated by laterally continuous transgressive marine shales which form their bases. The contact between Parasequences A and B appears sharp on well logs toward the southwest, but is difficult to identify toward the northeast so that parasequences A and B cannot be distinguished on well logs. Cores exhibit this sharp basal sandstone contact, as discussed below.

Sedimentology

The parasequence interpretation is supported by sedimentologic analysis of five cores from the Terry Sandstone. Locations of the cores are shown in Fig. 2-2. The five cores are:

Mach II-Rossi Petroleum 4-14 Aristocrat Angus, Sec. 2T3NR65W, stored at
USGS Library No. R726

Amoco Prod. 1 Vern Marshall, Sec. 32 T4NR65W, stored at
USGS Library No. R203

General Oil 1 Eckhardt, SENENE Sec. 15T4NR66W, stored at
USGS Library No. A609

Sotexco #1 Kinsman, Sec. 18T4NR65W, stored at CSM

Amoco Prod. Donald J. Moser No. 1, Sec. 34T4NR65W, stored at CSM

All cores except the Moser penetrated the lowermost sandy intervals, and all but the Moser core are within the southwesterly 'blocky to fining upward' trend (Figs. 2-2 and 5-1).

For each core, sedimentary textures, structures, and stratification sequences were described and facies identified. Trace fossils were also noted. Trace fossils identified in these cores include *Diplocraterion*, *Skolithos*, *Terebellina*, *Planolites*, *Chondrites*, *Ophiomorpha*, *Zoophycos*, and *Asterosoma*. *Inoceramus* fragments are also present. In these cores, and in general (Pemberton and MacEachern, 1995, Fig. 5) *Skolithos* is typical of shoreface strata and *Zoophycos* and *Inoceramus* most diagnostic of open shelf deposits. Facies discussed here are similar to those described for the Shannon Sandstone at Hartzog Draw Field by Bergman (1994).

Permeability measurements were made on most cores in the Petroleum Engineering Department with a pressure-decay permeameter. At each measurement point, % sand was estimated and facies and lithologies were identified. These data are discussed in detail in a later chapter.

A typical plot of % sand, facies, and pressure-decay permeability is shown on Fig. 5-4a alongside a gamma ray log of the Machii Ross Aristocrat well. The raw data are listed in Table 5-1.

The Machii Ross core typifies the sedimentology observed in most of the other cores. The lowermost interval from the base of the core to 4520ft. is comprised of bioturbated mudstone (about 95% mud). *Inoceramus* fragments and *Terebellina* (?) are present, suggesting an open shelf environment of deposition. This is interval A on Fig. 5-3.

From 4520 ft. to about 4503 ft., sediment is dominantly cross-bedded, fine-grained sandstone with occasional thin interbeds of burrowed to bioturbated muddy sandstone. *Skolithos* and *Chondrites* trace fossils are present. The contact between this sandstone and the underlying shelf mudstone is sharp, burrowed, and erosional. This interval is interpreted as upper shoreface strata deposited during progradation (Fig. 1-3 a and b). The sharp base of the shoreface deposits is interpreted to result from a sea level lowering during progradation (forced regression of Posamentier, et al., 1992; also see Fig. 1-3c for an analog). Thus, this base represents a depositional sequence boundary. It is the base of interval B (Fig. 5-3)

From 4503 ft to the top of the core at 4470 ft. the sediments are thin interbeds of burrowed to bioturbated muddy sandstone and sandy mudstone (generally 40-60% sand) containing Skolithos and Terebellina. Thin parallel- to cross-bedded-, clean, fine-grained sandstones occur sporadically throughout this interval. These sandstones have sharp bases and somewhat more gradational, finer-grained tops. This entire interval is interpreted as lower shoreface deposits (Figs. 1-3 a,b, and c). The clean sandstones are thought to be storm sediments deposited between fairweather and storm wavebase. The upper 3 ft. of core contains Zoophycos, suggesting more open shelf conditions.

About 10 ft. above the top of the core there is a distinctive shale horizon on the gamma ray log (not shown in Fig. 5-4a). This shale marks the transgressive marine shale (Fig. 5-3).

The Amoco Vern Marshall core penetrated three parasequences, A, B, and C (Fig. 5-3, well 9739). Core description is tabulated in Table 5-2. As is the case with the Machii Ross core, the basal interval (B in Fig. 5-3) is mainly sandstone with some shale and wispy silt laminae and remnant parallel- to cross-beds disrupted by bioturbation. The basal contact with underlying shale is not present in this core, but is presumably erosional based upon log character. This sandstone is also interpreted as upper shoreface strata.

The interval 4655ft.-4611ft. is comprised mainly of bioturbated, interlaminated sandstone and shale with occasional parallel- to cross-bedded thin sandstones. This is typical of the lower shoreface interval (4503ft. - 4570ft.) in the Machii Ross core. However, as shown in Fig. 5-3, a transgressive marine shale is interpreted to form the base of parasequence C at about 4645ft. This boundary was chosen because of a subtle shale kick on the gamma ray log. However there is nothing definitively different in the core between this and adjacent strata.

The cored interval 4611 ft. to the top of the core at 4590 ft. is comprised of laminated (not highly bioturbated) shale interpreted as a transgressive marine shale that forms the base of parasequence D (Fig. 5-3).

The Sotexco and Eckhardt cores penetrated the same interval as the Machii Ross and Vern Marshall cores, so are not discussed in detail. However, some features are worth noting. First, as mentioned above, a calcite-filled fracture was penetrated in the Eckhardt core, providing evidence that calcite was available at some time to fill fractures and faults. Second, the same basal, erosional contact between underlying shelf shale and upper shoreface sandstones described in the Machii Ross core also occurs in the Sotexco core. Third, the interval 4423 ft. - 4434 ft. in the Sotexco core contains a series of shale- and sandstone-clast breccias. Such features are not present in the other cores. The base of each breccia is sharp, and clast sizes decrease upward indicating size grading due to flow. Possibly this unusual deposit represents a debris flow or slump generated off the side of a shoreface (tidal??) channel.

The Donald Moser core is the only core to have penetrated the coarsening-upward interval (Fig. 5-4b). The lower part of this core is comprised of bioturbated shelf mudstone containing Zoophycos. This mudstone is gradational upward into bioturbated, Skolithos-bearing, thinly-interbedded sandy mudstone to muddy sandstone with occasional cleaner, cross-bedded storm

sandstones. The cored interval is interpreted as open shelf grading upward to lower shoreface. The D bentonite (Fig. 2-4) was penetrated in this core, which allowed verification that the 'hot' gamma-ray kick used to correlate well logs is the expression of a bentonite bed.

On the basis of the core descriptions, the following five facies were defined and numbered for comparison with permeability, tabulated and discussed in a later chapter. A sixth debris flow facies only occurs in the Sotexco core.

- Facies 1 = Bioturbated mudstone (to sandy mudstone) shelf facies
- Facies 2 = Burrowed to bioturbated sandy mudstone
(more sand and remnant laminations than 1)
- Facies 3 = Burrowed to bioturbated muddy sandstone
- Facies 4 = Planar to slightly x-bedded w/o burrows
- Facies 5 = Ripple-bedded sandstone, minor burrows
- Facies 6 = Mudstone/sandstone clasts in mud/sd. matrix
Debris flow bed

Interpretation and significance

With the exception of parasequence B, a transgressive shale forms the base of each parasequence in the eastern part of the study area. Individual parasequences typically grade eastward (paleo-seaward) from upper shoreface (blocky log pattern) to lower shoreface-shelf (coarsening/cleaning-upward log pattern) (compare Figs. 1-3a and 5-3). Transgressive shales are laterally continuous toward the east, thus have the potential to be significant vertical barriers to fluid flow. **In essence, the transgressive shales provide vertical stratigraphic compartmentalization of sandstone bodies (when not faulted) at right angles to the predominant horizontal structural compartmentalization.**

The history of development of the five parasequences represented in the Hambert-Aristocrat area is undoubtedly very complex. Numerous recent studies of superbly exposed outcrops of shoreface sequences, published in Van Wagoner and Bertram (1995), attest to their complexity and the numerous significant erosional surfaces that will not be detectable from subsurface well logs alone. Thus the interpretation put forth here is simplistic and subject to modification. Figure 5-5 illustrates our interpretation, discussed below, of the Hambert-Aristocrat parasequences.

The sequence boundary between Parasequences A and B (Fig. 5-3) is interpreted as a result of lowstand erosion during 'forced regression' (Fig. 1-3 b, and c; Posamentier, et al., 1992). Erosion undoubtedly removed the upper part of Parasequence A, so this sequence is not fully represented in core. After deposition of Parasequence A, a sea level lowering resulted in erosion and the farthest seaward extent of any parasequence observed in the Hambert-Aristocrat area. Upper shoreface strata were deposited on this sequence boundary in the southwest part of the study area, but appear to have graded seaward into lower shoreface and offshore deposits, based on our inability to trace this surface on well logs to the northeast (Fig. 5-3); apparently it is a conformable boundary toward the northeast. Ensuing relative stillstand (Kamola and VanWagoner, 1995) (i.e. reduction in rate of sea level rise or rate of sediment supply

exceeded/equaled rise of sea level) deposited lower shoreface strata above the upper shoreface deposits. With an increase in rate of relative sea level rise, a transgressive shale was deposited as the base of the next overlying parasequence.

Parasequences C, D, and E each exhibits a blocky log character, representing upper shoreface deposition, to the landward, and more shaley, and sometimes coarsening upward log character to the seaward (Fig. 5-3). However, the basically shalier character of Parasequences C and D, relative to B and E suggests that Parasequences C and D had backstepped (i.e. retrogradational) considerably more landward than B and E. Well logs comprising Parasequence E all exhibit a coarsening/cleaning upward pattern, suggesting seaward step (progradation) of a much more areally extensive lower shoreface-dominated sequence.

Since most hydrocarbon production from Hambert-Aristocrat Field occurs in upper shoreface sandstones immediately overlying the sequence boundary, from an exploration perspective it should be worth mapping this boundary regionally.

Gross interval and net sand isopachs of Parasequences A+B (Fig. 5-6 a and b) and C (Fig. 5-7 a and b) were constructed for the immediate Hambert-Aristocrat Field area to provide maps for Simulation. These isopachs show a distinct northwesterly trend. This trend is typical of Cretaceous marine sandstones in Rocky Mountain basins, and reflects gross paleoshoreline trends. In this instance, land was toward the southwest and the marine environment was toward the northeast.

CHAPTER 6

OUTCROP ANALOG

Mesaverde Group rocks as an analog

An outcrop analog was sought which exhibited the following attributes: (1) similar facies and stratification style as described above in Lambert-Aristocrat Field, (2) good lateral exposure so as to be able to observe and trace lateral continuity, and (3) observable fault offsets. Unfortunately, there are no suitable outcrop exposures of the Terry Sandstone in the Denver Basin area nor in Wyoming. Outcrops of the analog Hygiene (Shannon) Sandstone do occur along the west flank of the Denver Basin, but these are not laterally continuous, nor are fault offsets visible.

A suitable analog which exhibited these features was found within the Upper Cretaceous Mesaverde Group (along the Utah-Colorado border near Dinosaur, Colorado, northeastern Uinta Basin) (Fig. 6-1). The interval occurs as a steeply-dipping ridge, approximately 10 miles long and 150-300 ft. thick. On aerial photos and topographic maps (Fig. 6-2), the ridge---called Snake John Ridge---appears as a continuous sandstone interval except where offset by small faults. Although the tectonic regime in the Uinta Basin is different from that in the Denver Basin, the fault pattern which offsets the Ridge sandstone is analogous to the small-scale faulting which has offset the Terry Sandstone at Lambert-Aristocrat Field.

Several stratigraphic sections are exposed along the length of outcrop, including an excellent roadcut along U.S. Highway 40 (Fig. 6-3). According to Molenaar and Wilson (1992; Fig. 1), this section comprises the Castlegate and Sego Sandstones, and intervening Buck Tongue Member of the Mancos Shale (Fig. 6-4). The south-dipping Snake John Ridge can be traced into the subsurface (Fig. 6-3) where it forms gas-bearing sandstones (Figs. 6-5 a and b).

Snake John Ridge is comprised of a variety of shoreface, coastal, and fluvial depositional facies (Fig. 6-6); non-marine facies become more abundant to the west, in the paleolandward direction. Of most importance to the present study is the occurrence of multiple stacked shoreface sandstones which are superbly exposed in outcrop, and which can be traced laterally for several miles along strike. Parasequences are shown in Fig. 6-6 which are comprised of the same strata seen in core and correlated in the subsurface: (a) offshore, bioturbated shelf mudstone, (b) lower shoreface, thinly-interbedded burrowed sandstones and shales (some sandstones exhibit hummocky cross-beds and combined flow ripple bedding), c) upper shoreface, thick-bedded, trough cross-bedded to massive and burrowed sandstones with occasional thin shales, and c) reworked upper sandstone lag surfaces capped by transgressive marine shales (part of the next overlying sequence).

Significance of outcrop analog

This repetitive vertical succession and sedimentary characteristics are similar to those observed in cores and logs of the Terry Sandstone at Hambert-Aristocrat field. Thus, Snake John Ridge affords the opportunity to directly observe both the style of offset faulting which has compartmentalized the Terry Sandstone at Hambert-Aristocrat Field and the long-distance stratigraphic continuity of the shoreface sandstones and transgressive marine shales (when not offset by faults).

CHAPTER 7

PETROGRAPHY AND DIAGENESIS

Samples were collected from the following cores for petrographic and scanning electron microscope analysis:

- Amoco Prod. Co. Donald J. Moser #1 (SE NW Sec. 34, T. 4 N., R. 65 W.)
- Sotexco Inc. Kinsman No. 1 (SE SW Sec. 18, T. 4 N., R. 65 W.)
- Amoco Prod. Co. Vern Marshall #1 (NW SW Sec. 32, T. 4 N., R. 65 W.)

In addition, samples of the same facies were collected for comparison from the Prima Oil Burke 24-3S (SE SE Sec. 24, T. 4 N., R. 65 W.) in the Latham Bar Trend (Al-Raisi et al., 1996).

An epoxy-impregnated thin section was prepared for each sample. Visual inspection was made on each sample and framework and cement/matrix mineralogy was estimated, along with sorting, visual porosity, and visual permeability. These data, and general rock descriptions are provided in Tables 7-1 thru 7-4. Selected thin sections were also examined under a scanning electron microscope housed in the Department of Geology and Geological Engineering.

General Description

The sandstones examined from all four wells are generally fine-grained and well sorted, with variable amounts of carbonate cement. They are feldspathic, with twinned plagioclase being the predominant feldspar. Carbonate cement is mainly calcite, but carbonate clasts and fossil fragments are also present. Glauconite is usually present in small amounts, but is relatively abundant in a few samples (T2, T10, T11, B6; Table 7-1-4).

The sandstones typically exhibit an average grain size of 0.1-0.15mm. Thin section porosity ranges up to 15-20% in those sandstones with little or no carbonate cement. However, such high porosity is usually limited to relatively thin laminae. Muddy lamina or carbonate cement reduces average porosity. When the mud content exceeds a critical value, there is almost no visible porosity, probably mainly because of compaction.

Diagenesis

The degree of feldspar dissolution is relatively low. There is also little authigenic kaolinite in pores, which suggests there has been little meteoric water flushing through these sandstones.

Pressure solution of quartz occurs both as grain-to-grain pressure solution contacts and along stylolites. Pressure solution grain contacts and quartz overgrowths are commonly observed in sandstones which are not carbonate-cemented. In carbonate-cemented sandstones, quartz grains are cement-supported and corrosion of grain surfaces is common.

Stylolites form along clay laminae which are enriched in mica. The presence of mica seems to have enhanced quartz dissolution. These stylolites probably formed along primary concentrations of clay minerals and mica, and dissolution caused their concentration. Stylolites are not typically continuous over long lateral distances, thus reservoir fluids probably could migrate vertically, but only through a very tortuous path.

Carbonate cement is present in practically all sandstones examined, usually in concentrations between 10 and 30% (Table 7-1-4). Concentrations exceed 30% in some samples. Thus, it is evident that carbonate cement not only filled intergranular pore space, but also comprised carbonate clasts. Also, carbonate cement frequently occupies space which is of the same size as quartz grains in sandstones with <30% carbonate cement, suggesting that the original sand was a mixture of siliceous and carbonate grains, and that the carbonate grains were subsequently recrystallized to cement. Laminae with almost no carbonate or clay often exhibit extensive quartz cementation.

The above information suggests that facies with moderate carbonate cement and clay content have the best potential for preserved porosity.

Porosity type and distribution

Blue epoxy allows easy observation of large, interconnected pores. Thin sections of some of the tightest (low porosity) sandstones do not exhibit visual porosity (blue epoxy), indicating that almost all of the measured (core plug) porosity occurs in the form of microporosity which is too small to receive injected epoxy. The limiting pore throat size below which epoxy cannot be injected is not known at present.

Some thin sections were examined with back-scattered electrons under the scanning electron microscope. A back scatter image reflects both open pore space and epoxy-filled pore space. These analyses confirmed that most pores in the sandstones are on the order of a few microns in diameter (microporosity), and that there are very few large (>0.01mm) pores.

Core plug porosity measurements on some samples (i.e. Vern Marshall 4633.25; Sample 18; Table 7-1; porosity = 10.2%) are relatively high, yet no epoxy-filled porosity can be observed in thin section. If these porosity measurements are correct, most porosity must be microporosity, as discussed above. This conclusion was also reached by Pittman (1988).

Interpretation and significance

Stylolites are common in the Terry Sandstone in Hambert-Aristocrat Field. These stylolites may be significant vertical permeability baffles, resulting in a tortuous path for reservoir fluid flow.

The high carbonate cement content in these sandstones is thought to indicate the presence of common primary carbonate (sand) grains. Such grains may only have been available under certain

environmental or geochemical conditions. Porosity is more likely to be preserved in these carbonate cement-rich sandstones.

Even though core plug porosities of some sandstones are relatively high, the bulk of porosity in these sandstones appears to be microporosity (individual pores are only a few microns in diameter).

Pittman (1988) cites evidence for secondary porosity of the Terry Sandstone in this area. However, the fact that evidence of mineral dissolution is observed does not indicate that the dissolution process has resulted in any net gain in porosity. The Terry Sandstone in this area has been estimated to have been buried to depths corresponding to a maximum temperature of about 80-90°C (Pittman's Fig. 17). However, smectite/illite expandibility of only about 25% is cited, which suggests deeper burial. Porosities in these rocks seem low for sandstones which have supposedly not been buried >2km. It would be interesting to establish to what extent the maximum temperature experienced by the Terry Sandstone was controlled by burial under normal geothermal gradients, or by heat pulses caused by hydrothermal activity. If the latter is important, then the pathway of hot water flow will control reservoir properties. If on the other hand, geothermal gradients were normal, differences in Tertiary subsidence may be the controlling factor on burial temperatures. It is possible that these sandstones were overpressured at the time of maximum subsidence.

CHAPTER 8

SEDIMENTARY FACIES CONTROL ON PERMEABILITY

Permeability measurements

Permeability and porosity (i.e. reservoir quality) can be affected by primary sedimentary facies characteristics and by secondary diagenesis. From discussions in previous chapters, both have undoubtedly played a role in controlling permeability and porosity. As discussed earlier, there is a strong primary facies control on permeability in the Terry Sandstone at Latham Bar Trend, a few miles to the east of Lambert-Aristocrat Field. Diagenesis appears to have played a lesser, secondary role.

Permeability measurements were completed on all five cores described above. Measurements were made using a pressure decay permeameter housed in the Department of Petroleum Engineering. With this instrument, measurements are made over a mm size area of core, so that the permeability of thin beds can be accurately measured. This is unlike core plug measurements, which, in thin beds, actually only average the permeability (Fig. 8-1). By taking many permeability measurements with the pressure decay permeameter over short core intervals, a 'continuous' permeability profile can be established. Thus, permeability measurements were made at 0.17 ft. (2") intervals along the Macii Ross and Eckhardt cores and at 0.5 ft (6") intervals along the Vern Marshall, Moser and Sotexco cores.

Facies vs. permeability relationship

Figures 5-4 a and b illustrate the general relation, observed for all the wells, among the variables gamma-ray response, percent sand, facies (defined numerically in Chapter 5), and permeability. The sandy facies (Facies 4 and 5) exhibit the lowest gamma-ray response and highest permeabilities.

In order to evaluate the facies control on permeability in a more quantitative manner, a table was compiled of average % sand and permeability, and the distribution of permeability for each of the five cores (Table 8-1), from which a summary table of these data by facies was derived (Table 8-2). The data from this latter table were plotted as histograms which clearly illustrate the relation between permeability and the six facies. For example, comparison of Fig. 8-2 illustrates that the sandy Facies 4 and 5 also exhibit the highest permeabilities. Also, comparison of the frequency distribution of permeability for each facies (Fig. 8-3) shows the increasing permeability with sandiness of facies.

Relation of facies to production

Figure 8-3 also illustrates that permeability of these sandstones rarely exceeds 5md. Even the permeability of the best reservoir facies is normally <2md. Most production within Lambert-Aristocrat field appears to be from Facies 4 and 5, which in the majority of the study area occur at the base of the Terry Sandstone interval, in upper shoreface strata

(Fig. 5-3). However, Figs. 5-4 a and b show that even in lower shoreface strata, thin sandstone beds may exhibit permeabilities on the order of 1md. Even though spatial resolution is insufficient to resolve these thin bedded sandstones on routine well logs, they could be gas-bearing, and potentially gas productive upon artificial fracturing. Such thin sandstones, which contain variable, but significant amounts of clay matrix, will appear as low resistivity-low contrast intervals on well logs. The Vern Marshall well has been used to demonstrate their potential as pay sands (Slatt and Huffman, 1996) (Fig. 8-4)

As discussed in a previous chapter, shoreface deposits change systematically from fining-upward upper to lower shoreface in the paleo-landward direction to coarsening upward offshore to lower-middle shoreface strata in the seaward direction (Figs. 1-3 a,b, and c). Because permeability parallels facies or sandiness (Figs. 5-4 and 8-2), it is likely that the upper sandiest parts of the upward coarsening intervals in the eastern part of the study area might have hydrocarbon potential. These intervals, as well as the upper parts of shoreface parasequences toward the southwest, have not generally been perforated.

CHAPTER 9

CONCLUSIONS AND APPLICATIONS

1. A methodology is described for downloading a large database into PC format. This is the format that is most likely to be used by Independent oil and gas operators. Although the methodology is time-consuming to complete, once the database is built and purged of any well data deemed to be erroneous, it is possible to quickly generate multiple iterations of useful maps. However, it should be realized that the main utility of computer-generated contour maps is in providing generalities of structural and stratigraphic trends as well as in identifying erroneous well information.
2. Detailed structural mapping of the Hambert-Aristocrat area has reveals a very complex structural configuration. The same structural complexities have recently been mapped for the entire Denver Basin by Weimer (1996), who considers structure to be dominated by a regional northeast-trending, basement-controlled wrench-fault system.
3. In the Hambert-Aristocrat region, structural dip is gently toward the northwest. The gradient is about 40 ft. over a distance of about 9 mi., or about 4 ft./mi. However, there is considerable local structural variability owing to complex fault and associated fold patterns. The dominant fault trend is northeast, with a secondary northwest trend. Lateral offset on wrench faults has not been determined, but there is throw in the range 10-160 ft. in individual wells. At least 46 wells (2.3% of total wells) were interpreted as having fault cutouts within the Terry Sandstone. 3-D seismic over a limited area has verified some, but not all faults.
4. Within the Denver Basin, as well as other Rocky Mountain basins, a common problem has been the anomalous distribution of oil and gas wells producing within a given formation (i.e. an oil well might occur structurally higher than an adjacent gas well in close proximity). These anomalies, expressed by GOR's for individual wells, can be explained by considering the complexity of faulting, and resultant sandstone compartments bounded by faults. This GOR distribution, coupled with density log and core data, suggest at least some of the faults are sealing, and reservoir compartments are isolated.
5. The Terry Sandstone is comprised of five shoreface parasequences. These parasequences are comprised mainly of lower to upper shoreface strata toward the southwest (landward), which grade laterally into shelf to lower shoreface strata toward the northeast (seaward). Shoreface sandstone isopach trends are northwesterly, as is common for other Cretaceous Western Interior Seaway strata. Transgressive shales which form the base of parasequences, may provide vertical stratigraphic compartmentalization of sandstone bodies (when not faulted) at right angles to the predominant horizontal structural compartmentalization, particularly toward the eastern part of the study area. Thus, there probably is stratigraphic, as well as structural compartmentalization in Hambert-Aristocrat Field.

6. Most hydrocarbon production from Hambert-Aristocrat Field occurs in upper shoreface sandstones immediately overlying a sequence boundary. From an exploration perspective, it is worth mapping this boundary regionally.
7. The Sego-Castle Gate members of the Mesaverde Group along Snake John Ridge (Colorado-Utah border) provide an outcrop analog to the structure and stratigraphic architecture of shoreface strata in Hambert-Aristocrat field. Because Snake John Ridge is more-or-less laterally continuous for several miles, it affords the opportunity to directly observe (a) the style of offset faulting which has compartmentalized the Terry Sandstone at Hambert-Aristocrat Field and (b) the long-distance stratigraphic continuity of the shoreface sandstones and transgressive marine shales (when not offset by faults) which have stratigraphically compartmentalized the field.
8. Petrographic analysis of cores samples indicates stylolites are common in the Terry Sandstone in Hambert-Aristocrat Field. These stylolites may be significant vertical permeability baffles, resulting in a tortuous path for reservoir fluid flow. Also, petrography and scanning electron microscopy indicate the bulk of porosity in these sandstones is microporosity (individual pores are only a few microns in diameter).
9. A clear primary relation has been established between sedimentary facies and permeability of the Terry Sandstone in Hambert-Aristocrat Field. Diagenesis appears to have played a lesser, though significant role in controlling permeability. Upper shoreface sandstones exhibit the best permeability (app. 1md), and appear to provide most of the production. The same primary relationship had previously been established for the Terry Sandstone in the adjacent Latham Bar Trend, and is a common relationship in many sandstones.
10. Thin sandstones which are common in lower shoreface strata in Hambert-Aristocrat Field are relatively permeable, and contain variable, but significant amounts of clay matrix. Because of their clay content and thin bedding, they will appear as low resistivity-low contrast intervals on well logs. They may be gas-bearing in Hambert-Aristocrat field, thus affording additional production opportunities through artificial fracturing.
11. Several iterations in both structural and stratigraphic mapping have been completed for this study by different geologists. Not surprising is the fact that different structural and stratigraphic interpretations can be applied to the same rocks. However, in the case of the present study, these iterations have helped develop and refine our ideas of stratigraphic and structural compartmentalization, thus they are worthwhile. While there is always a degree of uncertainty in mapping, it is felt that the degree of uncertainty is diminished when time is taken to complete, discuss and analyze multiple iterations. Also, experience (further substantiated in this study) has demonstrated that structural and stratigraphic characterization of a petroleum field should not be confined to just the area of the field, but should be based upon somewhat more regional structural and stratigraphic mapping. A common problem in integrating disciplines for reservoir characterization is the temptation to only focus on the immediate area of the field, rather than broadening the study area to evaluate sub-regional structure and stratigraphy.

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Fig. 1-1 Location of Hambert-Aristocrat Field, Colorado (McKinnie, 1993).

Fig. 1-2 Map showing Cretaceous Western Interior Seaway of North America.

Fig. 1-3a Characteristics of shoreface parasequences (VanWagoner et. al., 1990).

Fig. 1-3b Evolution of sharp-based shoreface deposits in response to sea level fall (Posamentier, et al., 1992).

Fig. 1-3c Sedimentology and stratification of shoreface parasequences (Walker, 1992).

Fig. 1-4 Regional wrench fault structure, Denver Basin, Colorado (Weimer, 1996).

Fig. 1-5 Location of Antelope Field and Hambert-Aristocrat Field area (Siemers and Ristow, 1986).

Fig. 1-6a Blocky to fining-upward log response of Terry Sandstone. Brooks Expl. Inc. Firestein No. 1-30 (SW-SE Sec. 30, T. 6 N., R. 66 W.) (Siemers and Ristow, 1986).

Fig. 1-6b Coarsening/cleaning-upward log response of Terry Sandstone. Brooks Expl. Inc. Leffler No. 1 (NE-NW Sec. 21, T. 6 N., R. 66 W. (Siemers and Ristow, 1986).

Fig. 1-7a Isopach map of blocky to fining-upward sequence (Fig. 1-6a) in Antelope Field area (Siemers and Ristow, 1986).

Fig. 1-7b Isopach map of coarsening/cleaning-upward sequence (Fig. 1-6b) in Antelope Field area (Siemers and Ristow, 1986).

Fig. 1-8 Isopach of cross-bedded sandstone facies and faults in Latham Bar Trend (Al-Raisi et al., 1996).

Permeability measurements were made at 2 in (5 cm) intervals using a pressure decay profile permeameter.

Fig. 1-9 Permeability of different sedimentary facies, Latham Bar Trend (Al-Raisi et al., 1996).

32523: Normalized GOR values (cf/bbl) based on first year of production

(382): Top Terry Sandstone structural elevation above sea level (ft)

-----: Interpreted line for GOR = 15,000cf/bbl

/ : Fault

Fig. 1-10 Fault block interpretation and distribution of GOR's, Latham Bar Trend (Al-Raisi et al., 1996).

Fig. 1-11 Map view showing distribution of GOR's in relation to fault blocks, Latham Bar Trend (Al-Raisi et al, 1996).

Fig. 1-12 EUR vs. cross-bedded sandstone thickness in two fault blocks, Latham Bar Trend (Al-Raisi et al., 1996).

Fig. 1-13 Fault trends in Hambert Field based upon 2-D seismic (Davis, 1985).

Fig. 1-14 Early structure map of Hambert Field (Sonnenberg, 1982).

	R66W						R65W					
	6	5	4	3	2	1	6	5	4	3	2	1
T4N												
	7	8	9	10	11	12	7	8	9	10	11	12
	18	17	16	15	14	13	18	17	16	15	14	13
	19	20	21	22	23	24	19	20	21	22	23	24
	30	29	28	27	26	25	30	29	28	27	26	25
	31	32	33	34	35	36	31	32	33	34	35	36
T3N												
	6	5	4	3	2	1	6	5	4	3	2	1
	7	8	9	10	11	12	7	8	9	10	11	12
	18	17	16	15	14	13	18	17	16	15	14	13
	19	20	21	22	23	24	19	20	21	22	23	24
	30	29	28	27	26	25	30	29	28	27	26	25
	31	32	33	34	35	36	31	32	33	34	35	36

Fig. 2-1 Sub-regional Hambert-Aristocrat study area.

Fig. 2-2 Well and core locations in study area. Area of structure map refers to Fig. 3-3.

DOE RESERVOIR CHARACTERIZATION PROJECT GEOLOGICAL PROCESS DIAGRAM

Fig. 2-3 Database development flow process diagram.

Fig. 2-4 First pass stratigraphic picks of Terry Sandstone and adjacent bentonites.

TOP OF TERRY INTERVAL -- FIRST PASS

TOP OF TERRY INTERVAL -- SECOND PASS

Fig. 2-5 Frequency distribution of subsea depths, Top Terry Sandstone, before and after database editing.

TOP OF TERRY INTERVAL TO TOP OF MIDDLE SAND FIRST PASS

TOP OF TERRY INTERVAL TO TOP OF MIDDLE SAND SECOND PASS

Fig. 2-6 Frequency distribution of 'middle sand' isopach before and after database editing.

Fig. 2-7 Part of a computer-generated isopach map of the interval Top Terry Sandstone to D2 Bentonite, showing 'sinkholes', which in this case depict fault trends.

Fig. 3-1 Sub-regional structure contour map using the D2 Bentonite as a datum.

STRUCTURE CROSS-SECTION ON D2 BENTONITE

Fig. 3-2 Sub-regional structure cross section using the D2 Bentonite as a datum. Well GOR's are also shown. Location of cross section is shown on Fig. 3-1.

Fig. 3-3 First pass structure contour map off the Top 'middle sand' in the Hambert-Aristocrat Field. Well GOR's are plotted on the map.

Fig. 3-4 First pass structural cross section off the Top 'middle sand' in the Hambert-Aristocrat Field. Well GOR's are shown. Location of cross section is shown on Fig. 3-3.

TOP TERRY STRUCTURE MAP WITH CROSS SECTION LOCATION

Fig. 3-5 Structure contour map off the Top Terry Sandstone. Well GOR's are plotted on the map.

STRUCTURE CROSS-SECTION TOP TERRY SANDSTONE

Fig. 3-6 Structure cross section off the Top Terry Sandstone. Well GOR's are plotted on the map. Location of cross section is shown on Fig. 3-5.

Fig. 4-1 Fault compartmentalization and well GOR distributions of Muddy (J) andstone beneath Denver International Airport, Denver Basin (Weimer, 1996).

Fig. 4-2 Density and other logs in the Terry Sandstone interval, Amoco Edward Hemple Unit #2, Sec. 20, T. 4 N., R. 65 W.

CSM/DOE - Sussex
Preliminary Work Product
Contract No. DE-AC22-93BC14891

OPERATOR	AUNCO PRODUCTION COMPANY
WELL	EDWARD HUMBLE UNIT #2
COUNTRY	NEO
STATE	4400.0 - 4500.0
DEPT	04/01/78
DATE	05/13/0445
API NUMBER	4814.0
AGE	
PROCESS DATE	05/18/1995 / 09:32

SPOT LOCATION
1772 FWL 1938 FNL 29 4N 65W

CSM/DOE - Sussex
Preliminary Work Product
Contract No. DE-AC22-93BC14891
Task 1.1.2

OPERATOR	ELK Exploration
WELL	HSR Salisbury 6-29
COUNTRY	USA
STATE	DE
COUNTY	Salisbury
DATE LOGGED	11-28-91
DATE LOGGED	11-28-91
API NUMBER	15407
API NUMBER	15407
PROCESS DATE	05/15/1995 / 10:07

LOG CODE	15407320
LOG DATE	11-28-91
LOG TIME	10:07
LOG USER	ELK
LOG UNIT	FEET
LOG SCALE	1:1
LOG METHOD	GR
LOG TYPE	SHALE
LOG UNIT	FEET
LOG SCALE	1:1
LOG METHOD	GR
LOG TYPE	SHALE

Fig. 4-3 Density and other logs in the Terry Sandstone interval, Elk Exploration HSR Salisbury 6-29, Sec.29, T. 4 N., R. 65 W.

08534
ECKHARDT #1
15-4N 66W

Fig. 4-4 Eckhardt well showing location of cored interval and calcite filled fault/fractures.

20 4N 65W
16400

COARSEN-UP

35 4N 66W
16076

**BLOCKY
OR
FINING UPWARD**

Fig. 5-1 Two basic well log patterns of the Terry Sandstone in Lambert-Aristocrat area. Refer to figs. 1-6 a and b for similar patterns.

Fig. 5-2a Map of Hambert-Aristocrat area showing well locations and boundary between fining-upward and coarsening-upward log patterns.

Fig. 5-2c Map showing the distribution of the 'lower' and 'upper' sandstones.

Fig. 5-2b Stratigraphic cross section hung off the Top Terry interval. Location of cross section is shown in Fig. 5-2a.

Fig. 5-3 Southwest-northeast stratigraphic cross section showing Parasequences A-E in study area.

**MACII - ROSS
ARISTOCRAT ANGUS 4-14
SEC 4 - T3N - R65W
WELD COUNTY, COLORADO**

Fig. 5-4a Gamma-ray log and core parameters for Machii Ross well. See text for definition of facies 1-5.

#1 Donald Moser

Fig. 5-4b Gamma-ray log and core parameters for Donald Moser well. See text for definition of facies 1-5.

Fig. 5-5 Interpretation of Terry Sandstone parasequence development in Lambert-Aristocrat area.

Fig. 5-6a Net sand map of Parasequences A + B.

Fig. 5-6b Gross sand map of Parasequences A + B.

Fig. 5-7a Net sand map of Parasequence C.

Fig. 5-7b Gross sand map of Parasequence C.

FIGURE PC-2.1—Reservoirs in the Mesaverde Group play. Major (≥ 5 BCF) reservoirs are in black.

Era	System	COLORADO		
		UTAH	Southern Piceance Basin	Northern Piceance Basin
MESOZOIC	UPPER CRETACEOUS	Central Uinta Basin		
		North Horn Fm	Ohio Creek Mbr	Lance Fm
		Wasatch Fm	Mesaverde Fm	Fox Hills Ss
		Mesaverde Gp	Rollins Ss	Lewis Sh
		Tuscher Fm	Cozzene Sandstone	Williams Fork Fm
		Farrer Fm	Cocaine Ss	Trout Cr Ss
		Neslen Fm	Sage Ss	Iles Fm
			Castlegate Ss	Tow Cr Ss
				Loyd Ss
		Mancos Gp (main body)	Mancos Gp	Meeker Ss
		Frontier Fm	Morapos Ss	Mancos Gp
		Mowry Sh	Emery/Mancos 8' Ss	Niobrara Fm
		Dakota Ss	Mancos Gp	Mancos Gp
			Frontier Fm	Frontier Fm
			Mowry Sh	Mowry Sh

FIGURE PC-2.2—Stratigraphic column of the Upper Cretaceous interval in the Mesaverde Group play area (modified from Sheet 2). A combination of north and south Piceance Basin Mesaverde terminology is used in the text; the interval above the Rollins is termed the Williams Fork Fm. and the Rollins-Castlegate interval the Iles Fm.

Fig. 6-1 Location of outcrop study area, and stratigraphic position of Mesaverde Group, Uinta Basin, Colorado-Utah (McKinnie, 1993).

Fig. 6-2 Areal photograph of Snake John Ridge.

Fig. 6-3 Mesaverde stratigraphy at U.S. 40 road cut (outcrop study area) (Molenaar and Wilson, 1992).

Top Mesaverde Structure Contour Map

Fig. 6-4 Location of Snake John Ridge and subsurface structure off the Top Mesaverde. Locations of measured sections (Fig. 6-6), gas and possible oil wells are shown.

Fig. 6-5a Stratigraphic cross section of part of Mesaverde in Snake John Ridge area. See Fig. 6-4 for locations of wells.

Fig. 6-5b Stratigraphic cross section of part of Mesaverde in Snake John Ridge area. See Fig. 6-4 for locations of wells.

Fig. 6-6 Stratigraphic cross section of measured sections along Snake John Ridge. Locations of measured sections are shown on Fig. 6-4.

Fig. 8-1 Comparison of core plug measured permeability (19md) with spot permeability measurements on individual laminae (1.0, etc.) (Weber, 1987).

Fig. 8-2 Frequency distributions of % sand and permeability. Data are averages of 979 pressure decay permeability measurements from five cores. Estimates of sand content were made over the 0.5" interval where each permeability measurement was made on core. Raw and computed data are in Tables 8-1 and 8-2.

Fig. 8-3 Frequency distributions of permeability for the six facies comprising the Terry Sandstone in Hambert-Aristocrat Field. Raw and computed data are in Tables 8-1 and 8-2.

Fig. 8-4 Well and core data for Vern Marshall well. Note low resistivity zone. (Slatt and Huffman, 1996).

TABLE 2-1

Summary of Subsurface Depths for Formations
in Hambert-Aristocrat Study Area

Dwight Edington

3/1/94

FORMATION	MINIMUM	MAXIMUM	AVERAGE	FREQUENCY
Parkman Sltst	702	4048	3598	35
Parkman Ss	3560	3707	3649	4
Parkman Stst	3665	3665	3665	1
Rocky Ridge Ss	3605	3968	3713	43
Parkman/Rocky Ridge	3682	3877	3750	3
Parkman	3406	4065	3754	220
Bs Parkman	3669	3912	3790	4
Rocky Ridge	3573	4352	3795	43
Rocky Ridge/Parkman	3685	3911	3805	15
Rocky Road	3825	3825	3825	1
Bs Rocky Ridge Ss	3974	3986	3980	2
Minnelusa Red Mkr	4150	4150	4150	1
Sussex Ss	4078	4598	4320	156
Terry Ss	4204	4394	4341	4
Sussex	326	6902	4358	742
Sussex Por	4385	4385	4385	1
Sussex Zn	4202	4506	4396	10
Hambert Facies	4406	4406	4406	1
Hambert Sand Bs	4418	4418	4418	1
Sussex Ss Pay	4286	4597	4429	49
Bs Sandstone	4438	4438	4438	1
Sussex Pay Ss	4409	4461	4438	4
Cretaceous Bent	4444	4444	4444	1
Sussex Mkr	4428	4488	4445	6
Sussex Pay	4292	4618	4458	16
Sussex X Mkr	4459	4459	4459	1
Bs Sussex	4310	4772	4464	71
Basal Sussex	4480	4480	4480	1
Bs Sussex Ss	4405	4630	4513	14
Cretaceous Gn Mkr	4527	4527	4527	1

TABLE 2-2

Fields in COMPDATA.XLS Database File

							IP	IP	IP	IP	IP
							1-IP	1-IP	1-IP	1-IP	1-IP
	LATITUDE	LONGITUDE	API NUMBER	OWWO	RECORD	SSX PROD	BOPD	LIQUID TYPE	MCFGPD	BWPD	INITIAL POTENTIAL COMMENTS
1	40.252274	104.703766	0512314998	0000	R1626370		22	COND	340		F 22 BCPD grav 60; 340 MCFGPD on 9/64 ck; no wtr; FTP 2150, CP 2550
2	40.252274	104.703766	0512314998	0001	R1626371		16	COND	220		F 16 BCPD grav 60; 220 MCFGPD on 10/64 ck; no wtr; FTP 1500, CP 1700
3	40.248398	104.697845	0512314997	0000	R1626410		32	COND	474		F 32 BCPD grav 60; 474 MCFGPD on 11/64 ck; no wtr; FTP 2800, CP 2900
4	40.248398	104.697845	0512314997	0001	R1626411		23	COND	263		F 23 BCPD grav 60; 263 MCFGPD on 11/64 ck; no wtr; FTP 1800, CP 1800
5	40.248550	104.703796	0512315003	0000	R1626650		23	COND	339		F 23 BCPD grav 60; 339 MCFGPD on 9/64 ck; no wtr; FTP 2590, CP 2650
6	40.248550	104.703796	0512315003	0001	R1626651		16	COND	108		F 16 BCPD grav 60; 108 MCFGPD on 10/64 ck; no wtr; FTP 1800, CP 1950
7	40.201950	104.698639	0512315004	0001	R1626891						
8	40.259857	104.712524	0512315009	0000	R1627330		28	COND	306		F 28 BCPD grav 60; 306 MCFGPD on 10/64 ck; no wtr; FTP 2050, CP 2400
9	40.259857	104.712524	0512315009	0001	R1627331		15	COND	235		F 15 BCPD grav 60; 235 MCFGPD on 12/64 ck; no wtr; FTP 1050, CP 1300
10	0.000000	0.000000	0512315017	0000	R1627390		28	OIL	211	17	F 28 BOPD; 211 MCFGPD on 8/64 ck; 17 BWPD; CP 1100
11	40.249435	104.707993	0512315021	0000	R1627780		30	COND	339		F 30 BCPD grav 60; 339 MCFGPD on 10/64 ck; no wtr; FTP 2500, CP 2800
12	40.249435	104.707993	0512315021	0001	R1627781		12	COND	222		F 12 BCPD grav 60; 222 MCFGPD on 10/64 ck; no wtr; FTP 1000, CP 1300
13	40.252441	104.707932	0512315022	0000	R1628200		33	COND	346		F 33 BCPD grav 60; 346 MCFGPD on 10/64 ck; no wtr
14	40.252441	104.707932	0512315022	0001	R1628201		13	COND	244		F 13 BCPD grav 60; 244 MCFGPD on 10/64 ck; no wtr; FTP 1250, CP 1500
15	40.252426	104.712662	0512315023	0000	R1628210		37	COND	320		F 37 BCPD grav 60; 320 MCFGPD on 10/64 ck; no wtr; FTP 2400, CP 2700
16	40.252426	104.712662	0512315023	0001	R1628211		10	COND	173		F 10 BCPD grav 60; 173 MCFGPD on 10/64 ck; no wtr; FTP 1850, CP 1950

Records in COMPDATA.XLS Database File Continued

	IP	IP	IP	IP	IP	PERFS	PERFS	PERFS	PERFS
	2-IP	2-IP	2-IP	2-IP	2-IP	ZONE 1	ZONE 1	ZONE 1	ZONE 1
1	BOPD	LIQUID TYPE	MCFGPD	BWPD	INITIAL POTENTIAL COMMENTS	UPPER	LOWER	PRODFM	PERFS COMMENTS
2						7372	7385	Codell	7372-7385 (Codell) w/26 holes total - frac 133,000# 20/40 sd 51,200 gal gel wtr
3						7091	7262	Niobrara	7091-7262 (Niobrara) w/20 holes total - frac w/228,000# 20/40 sd 68,617 gal gel
4						7317	7332	Codell	7317-7332 (Codell) w/30 holes total - frac w/75,180 gal gel wtr 350,000# 20/40 sd
5						7039	7202	Niobrara	7039-7202 (Niobrara) w/20 holes total - frac w/228,000# 20/40 sd 69,362 gal gel
6						7380	7394	Codell	7380-7394 (Codell) w/28 holes total - frac w/75,522 gal gel wtr 350,000# 20/40 sd
7						7095	7266	Niobrara	7095-7266 (Niobrara) w/20 holes total - frac w/228,000# 20/40 sd 69,522 gal gel
8									
9						7382	7396	Codell	7382-7396 (Codell) w/28 holes total - frac w/75,480 gal gel wtr 345,000# 20/40 sd
10						7095	7266	Niobrara	7095-7266 (Niobrara) w/21 holes total - frac w/228,000# 20/40 sd 68,614 gal gel
11						7171	7183	Codell	7171-7183 (Codell) w/2 SPF 24 holes total - frac w/5000# 100 mesh sd 245,000# 20/40 sd 1856 bbl 40# & 35# gel 50 bbl oil
12						7402	7417	Codell	7402-7417 (Codell) w/23 holes total - frac w/350,000# 20/40 sd 5800 gal gel wtr
13						7118	7286	Niobrara	7118-7286 (Niobrara) w/20 holes total - frac w/228,000# 20/40 sd 67,624 gal gel
14						7392	7407	Codell	7392-7407 (Codell) w/30 holes total - frac w/311,000# 20/40 sd 70,898 gal gel fluid
14						7101	7278	Niobrara	7101-7278 (Niobrara) w/20 holes total - frac w/228,000# 20/40 sd 70,292 gal gel
16						7367	7382	Codell	7367-7382 (Codell) w/24 holes total - frac w/129,000# 20/40 sd 57,500 gal gel wtr
17						7072	7252	Niobrara	7072-7252 (Niobrara) w/21 holes total - frac w/254,300# 20/40 sd 71,100 gal gel wtr

TABLE 2-3

Fields in HEADER.XLS Database File

	LATITUDE	LONGITUDE	API	OWWO	SSC PROD	RECORD	SEC	TN	RN	SPOT	FOOTAGE	OPERATOR
1	40.274307	104.693665	512309686	0	1	R1022180	32	4	65	c nw nw	660 fml 660 fwl	MACEY & MERSHON OIL INC
2	40.270721	104.703156	512309691	0	1	R1022750	31	4	65	c sw ne	1980 fml 1980 fwl	CHAMPLIN PETROLEUM CO
3	40.309448	104.756958	512309871	0	1	R1059910	15	4	66	ne se	1850 fsl 990 fwl	NIELSON ENTERPRISES INC
4	40.329488	104.748154	512309876	0	1	R1060780	11	4	66	se nw	1530 fml 1490 fwl	AMOCO PROD CO
5	40.274445	104.689362	512309910	0	1	R4067770	32	4	65	ne nw	800 fml 1860 fwl	MACEY & MERSHON OIL INC
6	40.322327	104.673294	512309987	0		R1090440	9	4	65	sw sw	990 fsl 1040 fwl	WINTER HAWK LTD
7	40.314209	104.665085	512309998	0	1	R1092030	16	4	65	c sw ne	1980 fml 1980 fwl	WINTER HAWK LTD
8	40.314209	104.669861	512309997	0	1	R1092040	16	4	65	c se nw	1980 fml 1980 fwl	WINTER HAWK LTD
9	40.266678	104.688980	512310015	0	1	R1093230	32	4	65	ne sw	1800 fsl 1980 fwl	AMOCO PROD CO
10	40.306854	104.669815	512310005	0	1	R1094920	16	4	65	c se sw	660 fsl 1980 fwl	ENERGY OIL INC
11	40.309555	104.680450	512310013	0	1	R1095720	17	4	65	c sw ne se	1650 fsl 990 fwl	WINTER HAWK LTD
12	40.323318	104.766815	512310078	0	1	R1108510	10	4	66	c sw ne sw	1650 fsl 1650 fwl	COLTON & COLTON CO
13	40.310486	104.664871	512310090	0		R1114250	16	4	65	e/2 nw se	1980 fsl 1920 fwl	ENERGY OIL INC
14	40.310486	104.664871	512310090	0		R1114251	16	4	65	e/2 nw se	1980 fsl 1920 fwl	SNYDER OIL CORP
15	40.277832	104.669922	512310105	0	1	R1116380	28	4	65	c se sw	660 fsl 1980 fwl	ENERGY OIL INC
16	40.315231	104.765564	512310108	0	1	R1117270	15	4	66	e/2 nw	1320 fml 2000 fwl	HOMESTEAD OIL CO INC
17	40.259949	104.698486	512310134	0	1	R1124340	6	3	65	c ne ne	660 fml 660 fwl	MARTIN EXPL MGMT CORP
18	40.177246	104.692810	512310142	0		R1126780	32	3	65	c ne sw sw	990 fsl 990 fwl	CALVIN PETROLEUM CORP
19	40.199341	104.671417	512310171	0		R1132740	28	3	65	se nw	1570 fml 1650 fwl	M G F OIL CORP
20	40.199341	104.671417	512310171	0		R1132741	28	3	65	se nw	1570 fml 1650 fwl	M G F OIL CORP
21	40.245331	104.679504	512309336	0	1	R1135570	8	3	65	c ne en	660 fml 660 fwl	MACHII ROSS PETR CO
22	40.249786	104.633240	512310198	0		R1138060	2	3	65	c nw se nw	990 fsl 1650 fwl	EXCEL ENERGY CORP

Records in HEADER.XLS Database File Continued

LEASE & WELL	ELEVATION	EREF	FIELD	PTD	TD	PHTD	OJBECTIVE	FMTD	SPUDDATE	COMPL-DATE	FC	FSTAT
1 MUSICK & MCCLINTOCK #3	4900	KB	UNNAMED	4725	4762	4716	Sussex		19790314	19790803	0	OIL
2 RURAL (32-31) #2	4862	GR	HAMBERT	4700	4698	4650	Sussex		19790307	19790722	OG	O&G
3 ECKHARDT #2	4744	KB	HAMBERT	4550	4572	4534	Sussex	Sussex	19800129	19800425	OG	O&G
4 UPRR 21 PAN AM #H-1	4708	GR	HAMBERT	4550	4556	4509	Sussex	Sussex	19800105	19800913	D	P&A
5 MUSICK-MCCLINTOCK #5	4904	KB	HAMBERT	4725	4752	4712	Sussex		19800228	19800524	OG	O&G
6 REICHERT #9-2J	4739	KB	WATTENBERG	7500	7688	7685	J Sand	Skull Creek	19800701	19810110	G	GAS
7 MEYER #16-1	4784	KB	HAMBERT	4500	4555	4550	Sussex	Sussex ss	19800703	19801022	OG	O&G
8 HEINLE #16-2	4779	KB	HAMBERT	4500	4565	4560	Sussex	Sussex	19800628	19801025	OG	O&G
9 CLYDE MARSHALL #1	4947	KB	HAMBERT	4750	4765	4716	Test	Sussex	19800801	19810416	OG	O&G
10 BOULTER #1	4839	KB	HAMBERT	4575	4623	0	Sussex	Sussex	19800708	19801113	OG	O&G
11 WALKER #17-1	4782	KB	HAMBERT	4600	4571	4565	Sussex	Sussex	19800714	19810110	OG	O&G
12 BROWN-MONFORT #1	4725	KB	HAMBERT	4500	4500	0	Sussex		19800929	19810219	G	GAS
13 BRUNTZ #1	4795	KB	HAMBERT	4620	7275	0	Sussex		19810604	19810806	O	OIL
14 BRUNTZ #1	4795	KB	HAMBERT	7071	0	0	Niobrara		0	0		
15 KRAUSE #1	4854	KB	HAMBERT	4650	4669	4634	Sussex	Sussex	19810111	19810506	G	GAS
16 STATLER #1	4740	KB	HAMBERT	4575	4580	4540	Sussex		19801031	19810408	G	GAS
17 MCKENNEY - KNAUB #5-6	4785	KB	HAMBERT	4795	4715	0	Sussex	ben-tonite	19810107	19810716	OG	O&G
18 MILE HIGH TURKEY FARM #1-32	4914	GR	WATTENBERG	7900	7879	0	J Sand		19810102	19811103	G	GAS
19 MOSER #22-28	4840	KB	WATTENBERG	7850	7898	7888	J Sand	Lakota	19810122	19810319	G	GAS
20 MOSER #22-28	4840	KB	WATTENBERG	7850	7898	7580	Codell	Lakota	19921118	19930112	O	OIL
21 ARISTOCRAT ANGUS RANCH #41-81	4865	KB	ARISTOCRAT	4600	4643	0	Sussex		19810201	19810625	OG	O&G
22 JEPSEN #1	4775	KB	WATTENBERG	7650	7655	0	J Sand	J Sand	19810212	19810625	G	GAS

TABLE 2-4

IPTEXT.XLS

REC	IPTEXT1	IPTEXT2
R1022180	F 135 BO grav 44 340 MCFGPD no wtr GOR 2585:1	0
R1022750	F 17 BOPD, 123 MCFGPD, 7 BWPD	0
R1059910	F 3 BOPD, 482 MCFGPD, 30/64 ck	0
R1067770	68 BOPD grav 49, 312 MCFGPD, 35 BWPD, CP 200, GOR 4588:1	0
R1090440	F 150 MCFGPD on 16/64 ck 5 BWPD FTP 100 CP 490	0
R1092030	F 25 BOPD grav 42, 90 MCFGPD 15 BWPD CP 375# FTP 150# on 18/64 ck GOR 3.6:1	0
R1092040	F 20 BOPD grav 42, 85 MCFGPD, 6 BWPD on 18/64 in ck FTP 160 CP 240	0
R1093230	F 23 BCPD grav 54.7, 1350 MCFGPD on 28/64 ck, 10 BWPD	0
R1094920	P 17.7 BOPD grav 44, 78 MCFGPD 11 BWPD FTP 200 CP 300	0
R1095720	F 17 BOPD grav 42, 50 MCFGPD on 16/64 ck FTP 50 CP 480 GOR 1:3	0
R1108510	F 2 BOPD, 100 MCFGPD on 20/64 ck, 26 BWPD, FTP 120 CP 260 GOR 50,000:1	0
R1114250	(Codell 7179-7192) -- F 20 BOPD; 225 MCFGPD	0
R1116380	F 28 BOPD grav 44, 320 MCFGPD on 18/64 ck, 7 BWPD, FP 40 CP 210	0
R1117270	F 2 BOPD grav 60, 158 MCFGPD on 25/64 in ck, 47 BWPD FTP 180 CP 385	0
R1124340	F 208 MCFGPD, 108 BOPD, 80 BWPD, CP 190	0
R1126780	F 2 BCPD, 140 MCFGPD (Operator Report) 1 BOPD, 156 MCFGPD, 16 BFWPD TP 150 CP 350 (Final Report)	0
R1132740	(J Sand 7631-7692) -- F 1 BCPD grav 60; 1755 MCFGPD on 1 3/4 ck; no wtr FTP 1625, FCP 1674	0
R1132741	(Codell 7188-7203 01/08/93) -- GL 12 BOPD; 85 MCFGPD; no wtr	(Codell 7188-7203) -- F 7 BCPD grav 52; 80 MCFGPD on 16/64 ck; no wtr FTP 200, SICP 400
R1135570	F 76 BOPD grav 56, 400 MCFGPD on 21/64 ck, CP 500, TP 350	0

TABLE 2-5

GORALL.XLS

GORALL.XLS - 13TH MONTH GOR DATA, SUSSEX LEASES, DWIGHT'S PROD DATA																
NAME	LOC	API	FLD/RES		ZONES	TYPE	13MO	GAS	CUMGAS	OIL	CUMOIL	PGRV	13GOR	AVGGOR	#WELLS	
AMOCO PRODUCTION CO	LORENZ, CHRIS	28 4N 66W 0512307233	WATTENBERG	SSX-COD		2 OIL	MAY	2404	29704	80	577	62.1	40067	51480		1
AMOCO PRODUCTION CO	UPRR #39 PAN AMERICAN /BA	13 3N 65W 0512307244	WATTENBERG	SSX		1 GAS	FEB	2089	36385	82	357		25478	101819		-99
AMOCO PRODUCTION CO	WARDELL, J J, /A/	8 3N 65W 0512307285	WATTENBERG	SSX		1 GAS	OCT	1707	38188	20	490		85350	77890		-99
AMOCO PRODUCTION CO	STATE OF COLORADO /ZA/	38 4N 66W 0512307290	WATTENBERG	SSX		1 GAS	FEB	2492	40545	50	459	58.3	49840	88333		-99
AMOCO PRODUCTION CO	ARENS, FRANCES G	15 4N 65W 0512307507	WATTENBERG	SSX		1 OIL	XXX	-99	-99	-99	-99	0	-99	-99		-99
CHURCHILL ENERGY INC	KINSMAN	18 4N 65W 0512307545	HAMBERT	SSX		1 GAS	JUL	4708	78064	173	1912	59.2	27202	41361		-99
AMOCO PRODUCTION CO	OSTER, DAN, UNIT	10 4N 65W 0512308156	WATTENBERG	SSX		1 GAS	JUN	681	19873	0	419	0	-99	47430		-99
BASIN OPERATING CO LTD	ECKHARDT #1	15 4N 66W 0512308534	HAMBERT	SSX		1 GAS	FEB	4920	113030	39	1134		126154	99874		-99
NIELSON ENTERPRISES INC	MONFORT SENW	10 4N 66W 0512308555	HAMBERT	SSX		1 GAS	FEB	78	976	0	86		-99	11348		-99
AMOCO PRODUCTION CO	UPRR #21 PAN AMERICAN UT	7 4N 65W 0512308925	HAMBERT	SSX		1 GAS	JAN	1054	18171	0	0	0	-99	-99		-99
COLTON & COLTON ETAL	WERNING SW NW	2 4N 66W 0512309002	HAMBERT	SSX		1 GAS	XXX	-99	-99	-99	-99		-99	-99		-99
MACHII ROSS PETROLEUM CO	SEGAL 21 & 41-24, *SAM	24 4N 66W 0512309053	HAMBERT	SSX		1 GAS	APR	42888	592738	401	4878	63.2	106903	121582		-99
VESSELS OIL & GAS CO	DINNER #1	14 4N 66W 0512309106	HAMBERT	SSX		1 GAS	JAN	21228	283212	142	1561		149483	182600		-99
AMOCO PRODUCTION CO	CRAVEN, HAROLD, UNIT	17 4N 66W 0512309107	HAMBERT	SSX		1 GAS	APR	844	20424	0	0	0	-99	-99		-99
AMOCO PRODUCTION CO	MILLER, L H, UNIT	26 4N 66W 0512309118	HAMBERT	SSX		1 GAS	APR	7648	167815	0	0	67.3	-99	-99		-99
VESSELS OIL & GAS CO	MCCARTHY #1 NW NW	12 4N 66W 0512309169	HAMBERT	SSX		1 GAS	XXXX	-99	-99	-99	-99	51	-99	-99		-99
MACHII ROSS PETROLEUM CO	MYRON MARTINSON 14-24	24 4N 66W 0512309281	HAMBERT	SSX		1 GAS	JAN	1146	21413	99	1926		11576	11118		-99
CHURCHILL ENERGY INC	STROMBERGER #2-12	12 4N 66W 0512309299	HAMBERT	SSX		1 GAS	MAR	1887	35092	95	2356	62.5	19963	14897		-99

RECORD	CORE	#	TOP	BASE	FM	FMCD	NARRATIVE
R1185000	Core	1	7038	7089	Fort Hays/Codell	213	cut & rec 33. 2 ft: Ls, vf gr, perm 0.01-0.07 md, por 4.2-5.6%, oil sat 0.0%, Sw 69.0-77.4%; 1 ft: Ls, vf gr, perm 0.01 md, por 4.0%, oil sat 21.6%, Sw 60.5%; 1 ft: Ls, vf gr, pyr, perm 0.09 md, por 4.5%, oil sat 0.0%, Sw 63.2%; 4 ft: Ls, vf gr, perm 0.01
R9169480	Core	1	4470	4530		0	cut 60 rec 30
R1454020	Core	1	10471	10501	Fountain	324	cut 30 rec 24
R1454020	Core	2	10665	10692	Fountain	324	cut 27 rec 12
R1454020	Core	3	10807	10822	granite	0	cut & rec 15
R1454020	Core	4	10822	10827	granite	0	cut & rec 5
R9007180	Core	1	4452	4475		0	rec 22
R9007180	Core	2	4478	4495		0	cut 19 rec 15
R9007180	Core	3	4495	4514		0	cut 19 rec 6
R9007190	Core	1	7570	7588		0	
R9007190	Core	2	7588	7634		0	
R9092540	Core	1	7648	7701		0	
R1573270	Core	1	7534	7540	J Sand	218	cut & rec 6. #2 7540-7547 (J Sand) cut & rec 7. #3 7547-7575 (J Sand) cut & rec 28.
R9011130	Core	1	7677	7734		0	
R1518360	Core	1	0	0		0	No details available yet
R9013790	Core	1	4353	4421	Sussex	211	cut & rec 68. 1 ft: Ss, gry, f gr, slty, shly, cl, perm 0.3 md, por 8.4%, oil sat 1.1%, Sw 74.9%; 10 ft: Sh, no analysis; 1 ft: Ss, gry, f gr, slty, cl, perm 0.1 md, por 9.5%, oil sat 0.0%, Sw 55.5%; 10 ft: Sh, no analysis; 1 ft: Ss, gry, f gr, slty, cl,
R9013790	Core	1	4353	4421		0	
R9013790	Core	2	7518	7580		0	
R1242490	Core	1	7014	7047	Fort Hays/Codell	213	
R9023080	Core	1	7515	7540		0	7515-7516 Ss gry vfg cly shly 7516 7518 Ss gry vfg cl slty carb 7518 7520 Ss gry vfg cly slty 7520 7525 Ss gry vfg cly slty carb 7525 7526 Ss gry fn v/cly slty carb 7526 7531 Ss gry vfg v/vly slty carb 7531 7540 Ss wh vfg v/cly slty
R1208310	Core	1	4364	4422	Sussex	211	cut 58 rec 56.
R1208310	Core	2	7000	7050	Codell	213	cut & rec 50.
R9003640	Core	1	4370	4401		0	rec 31
R9003640	Core	2	4401	4451		0	rec 43 ft

SSXDATA.XLS

SSXDATA.XLSA-106

TABLE 2-7B

SSXDATA.XLS

36	37	38	38.1	39	63	64
COMPODATA	COMPOAT	COMPOAT	COMPOATA	COMPOATA		
ZONE 1	IPGRAV1	IPGOR1	GORCALC	IPTEXT1	PRODDATA	LOC
PERFS COMMENTS					PRODUCER & LEASE	
4426-4485 (Summit) w/8 JSF 166 holes tot	-89	-899	-899		AJOCO PRODUCTION CO	2 4N 65W
- BP @ 6929 4418-4432 (Summit) w/85 hole	-89	-899	64444 F 9 BOPO: 580 MCFGPD on 14/		PRIMA OIL & GAS CO	24 4N 65W
4476-4484 (Summit) w/85 holes total - frac	-89	-899	51111 F 9 BOPO: 460 MCFGPD on 11/		PRIMA OIL & GAS CO	24 4N 65W
4376-4383 (Summit) w/22 holes total - frac w/83,000 gal w/8 clay/99	-89	-899	31000 (Summit 4376-4383) - F 5.3 BO			
- BP @ 6400 4376-4383 (Summit) w/26 hole	-89	-899	20381 (Summit 4376-4383) - F 23 BO		SHYDER OIL CORP	15 4N 65W
4433-4462 (Summit) w/30 holes total - frac	-89	-899	28600 (Summit 4433-4452) - F 10 BO			
4362-4386 (Summit) w/28 holes total - frac	-89	-899	22800 (Summit 4362-4386) - F 20 BO		SHYDER OIL CORP	23 4N 65W
- CSP @ 7090 4435-4485 (Summit) w/2 BP	-89	-899	13237 F 38 BOPO: 503 MCFGPD: 12.8		SHYDER OIL CORP	23 4N 65W
- Recompletion July 1986: CSP @ 4580 - P	-89	-899	1677 F 83 BOPO: 165 MCFGPD: 80.8		COORS ENERGY CO	3 3N 65W
- Recompletion October 1986: Pugged back 1	-89	-899	6804 F 66 BOPO: 381 MCFGPD: 60.8		COORS ENERGY CO	10 3N 65W
- Recompletion July 1986: CSP @ 4558 - P	-89	-899	18222 F 18 BOPO: 328 MCFGPD: 10.8		COORS ENERGY CO	3 3N 65W
4432-4482 (Summit) w/2 SP - frac w/250.0	-89	-899	178000 F 3 BOPO: 528 MCFGPD: 3 BWP		COORS ENERGY CO	10 3N 65W
- Recompletion Aug. 1986: Part 4412-4478 1	-89	-899	8288 F 66 BOPO: 454 MCFGPD: 20.8		COORS ENERGY CO	10 3N 65W
4460-4522 (Summit) w/2 SP - acid w/500 g	-89	-899	2177 F 23 BOPO: 6 MCFGPD: 11 BWP		COORS ENERGY CO	4 3N 65W
4377 (Summit) w/2 SP - frac w/300,000 g	-89	-899	5488 F 81 BOPO: 477 MCFGPD: 30.8		COORS ENERGY CO	3 3N 65W
4377-4446 (Summit) 5817-5846 (Dishorn)	-89	-899	6276 F 58 BOPO: 354 MCFGPD: 40.8		COORS ENERGY CO	3 3N 65W
4626-4685 (Summit) @ 4626-4634 4646-46	-89	-899	46870 F 32/64 ch 33 BOPO 1660 MCF		UNION PACIFIC RESOURCES	5 3N 65W
4476-4638 (Summit) @ 4476-4488 4602-46	-89	-899	3276 F 68 BOPO: 180 MCFGPD on 26		UNION PACIFIC RESOURCES	9 3N 65W
4622-4646 (Summit) w/2 JSF - frac w/2570	-89	-899	112857 F 22/64 ch 7 BLO 790 MCFGPD			
4470-4518 w/1 SP - acid w/300 gal acid	44	58633	58633 F 18 BOPO grav 44, 1077 MCFG			
4462-4510 (Summit) w/2 SP - treat w/12 bn	-89	-899	36800 F 10 BOPO: 368 MCFGPD: no w			
4426-4484 (Summit) w/4 SP - frac w/250.0	-89	-899	15385 (Summit 4426-4484) - P 13 BO			
4433-4496 (Summit) w/1 SP - treat w/300 g	-89	-899	3089 F 71 BOPO grav 45, 220 MCFGPD		COORS ENERGY CO	3 3N 65W
4422-42 (Summit) w/1 shut-in w/250,000 g	50	10	5408 F 76 BOPO grav 50, 411 MCFGPD			
4454-4515 (Summit) w/1 SP - treat w/1663	44	795	79545 F 11 BOPO grav 44, 875 MCFGPD			
4380-4444 w/1 SP - frac w/296,000 g 20/4	52	-899	58625 F 6 BOPO: 440 MCFGPD 0/grav		COORS ENERGY CO	3 3N 65W
4464-4611 (Summit) w/1 SP - treat w/300 g	44.5	155	15500 F 40 BOPO grav 44.5, 620 MCF			
4400-4470 (Summit) w/1 SP - acid w/500 b	52	-899	41400 F 6 BOPO grav 52, 207 MCFGPD		COORS ENERGY CO	3 3N 65W
4502-4640 (Summit) w/1 SP - treat w/1726 b	43	500	5000 F 80 BOPO grav 43, 400 MCFGPD			
4448-4510 w/1 SP - treat w/300 gal acid 16	43.4	399	3997 F 158 BOPO grav 43.4, 630 MCF		COORS ENERGY CO	4 3N 65W
4463-4618 - w/2SP - treat w/300 gal 19500	-89	29578	29578 F 19 BOPO 562 MCFGPD on 12/		COORS ENERGY CO	4 3N 65W
4376-4482 (Summit) w/1 SP @ 4376-85 44	51	-899	5453 F 43 BOPO grav 51, 264 MCFGPD		COORS ENERGY CO	4 3N 65W
4476-4540 (Summit) w/1 SP - frac w/897 b	56	-899	5263 F 76 BOPO grav 56, 400 MCFGPD		NORTH AMERICAN RESOURCES	8 3N 65W

SSXDATA.XLS

65	66	67	68	69	70	71	72	73	74	75	76	77	78
PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA	PRODDATA
KEYAP	FLD	RES	ZONES	TYPE	13MO	GAS	CUMGAS	OK	CUMOL	PGRAV	13GOR	AVGGOR	FWELLS
0512316357	HAMBERT	SSX	1 GAS	MAR	465	1516	0	10			-99	151500	-99
0512311488	WATTENBERG	SSX	1 GAS	JAN	5787	85226	72	1047	63.5	80376	81400	-99	-99
0512314684	WATTENBERG	SSX	1 GAS	SEP	4080	108409	58	1514	68.3	70345	71604	-99	-99
0512316428													
0512315427	WATTENBERG	SSX	1 OIL	XXX	-89	-89	-89	-89	50	-89	-89	-99	-99
0512316352													
0512316350	WATTENBERG	SSX-COO	2 OIL	XXX	-89	-89	-89	-89	80	-89	-89	-99	-99
0512316351	WATTENBERG	HO8-COO-SSX	3 GAS	XXX	-89	-89	-89	-89	83	-89	-89	-99	-99
0512312821	ARISTOCRAT	HO8-COO-SSX	3 OIL	FEB	7685	53357	362	3651	21280	14614		2	
0512312805	ARISTOCRAT	SSX	1 OIL	JAN	1138	34435	71	2282	16028	10795		1	
0512312718	ARISTOCRAT	HO8-COO-SSX	3 OIL	NOV	12826	64868	528	3328	24481	19454		2	
0512312385	ARISTOCRAT	HO8-COO-SSX	3 GAS	APR	0	67866	0	3446	-89	19697	-89	-89	-89
0512312806	ARISTOCRAT	HO8-COO-SSX	3 OIL	DEC	4885	120030	348	8411	53.4	14449	12754	2	
0512312720	ARISTOCRAT	HO8-COO-SSX	3 OIL	NOV	2977	67432	724	6304	4112	10697		2	
0512312762	ARISTOCRAT	HO8-COO-SSX	3 GAS	JAN	14689	84203	644	3874	22825	21736	-99	-99	-99
0512309728	ARISTOCRAT	SSX	1 GAS	JUL	28464	629099	681	12443	66	45649	42622	-99	-99
0512309726	ARISTOCRAT	SSX	1 GAS	AUG	5898	127417	410	12978	50	14825	10688	-99	-99
0512309682													
0512309300													
0512313669													
0512313661													
0512309328	ARISTOCRAT	SSX	1 GAS	JAN	328	6370	24	336		13667	19016	-99	-99
0512309497													
0512309330													
0512310323	ARISTOCRAT	SSX	1 GAS	JAN	0	4638	0	51		-89	90941	-99	-99
0512309332													
0512309329	ARISTOCRAT	SSX	1 GAS	JAN	1098	18996	9	866		122111	20720	-99	-99
0512309333													
0512309334	ARISTOCRAT	SSX	1 GAS	MAR	38531	683265	1073	22714		35910	30061	-99	-99
0512309331													
0512309335	ARISTOCRAT	SSX	1 OIL	JAN	276	16355	0	2363		-89	6921	2	
0512309336	ARISTOCRAT	SSX	1 OIL	JAN	856	23833	4	1930		214000	12349	1	

TABLE 2-8A

INPUT.XLS

8:45 PM

- LOG DATA WORKING FILE - LIVE CELLS

LOG DATA WORKING FILE - LIVE CELLS

WELL CHG	UNIQUE	LOG	SPOT	OPER	LEAS & WELL	DOWHOLE ELEV	DOWHOLE ELEV REF	LOG ELEV REF	ADHENTRY	SHAPE	TOP DECK	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHAPE SOT	SHA
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A-108

TABLE 2-8B

STX.LINK

9636278

[illegible]

TABLE 5-1

Machi Ross

A-110

samples taken every 2"		Machii Ross Petrol Co. Aristocrat Angus #14-4 3N-65W-Sec. 4							
4470' top of core									
Point	Depth	KI	Facies	%sd	%sh	Lithology			
295	4470	0.0209	5	100	0	x-bed fn sd w/sharp base (4470')			
294	4470.17	0.0608	5	35	65	bioturb. sd/sh remnant lam			
293	4470.33	0.204	2	45	55	"			
292	4470.5	0.125	2	50	50	" Zoophycos			
291	4470.67	0.2	3	50	50	"			
290	4470.83	0.605	2	30	70	" Terebellina			
289	4471.1	0.888	3	50	50	"			
288	4471.27	0.956	2	35	65	"			
287	4471.44	1.07	2	25	75	" Zoophycos			
286	4471.6	0.929	2	40	60	"			
285	4471.77	1.08	2	40	60	"			
284	4472.08	4.17	3	55	45	"			
283	4472.25	1.22	3	50	50	"			
282	4472.42	0.758	2	40	60	"			
281	4472.58	0.721	2	40	60	"			
280	4472.75	0.844	2	25	75	" lowest occurrence of Zoophycos			
279	4473	1.11	2	40	60	"			
278	4473.17	1.66	2	45	55	"			
277	4473.33	0.51	2	95	5	"			
276	4473.5	0.848	3	50	50	"			
275	4473.67	0.859	3	50	50	"			
274	4474.03	0.74	3	50	50	"			
273	4474.2	1.74	3	50	50	"			
272	4474.36	1.76	5	95	5	"			
271	4474.53	1.35	2	45	55	Some rippled sd with F3 interval			
270	4474.7	0.633	2	40	60	Probably qualifies as F2a. Could be some			
269	4475	0.255	2	30	70	other subtle genetic units w/in 247-271 unit			
268	4475.17	0.586	2	40	60	"			
267	4475.33	0.926	2	40	60	"			
266	4475.5	0.346	3	75	25	"			

265	4475.67	1.71	4	90	10	"			
264	4475.83	0.551	2	40	60	"			
263	4476.07	1.02	3	70	30	"			
262	4476.24	3.46	3	50	50	"			
261	4476.41	1.48	2	45	55	"			
260	4476.57	0.801	2	40	60	"			
259	4476.74	0.656	2	30	70	"			
258	4477.06	0.466	3	55	45	"			
257	4477.23	1.29	2	25	75	"			
256	4477.4	1.37	3	50	50	"			
255	4477.56	0.505	2	30	70	"			
254	4477.73	0.318	2	20	80	"			
253	4478.08	1.09	2	40	60	"			
252	4478.25	1.97	3	60	40	"			
251	4478.42	0.577	2	45	55	"			
250	4478.58	0.642	3	50	50	"			
249	4479	3.04	3	50	50	"			
248	4479.17	0.19	5	100	0	Parallel X-bed fn sd			
247	4479.33	0.205	4	100	0	"			
246	4479.5	0.501	3	90	10	bloturb. sd/sh remnant lam -rippled sd.			
245	4479.67	0.344	2	40	60	"			
244	4480.02	0.713	3	75	25	" 4480'			
243	4480.19	1.17	3	70	30	"			
242	4480.35	0.879	3	55	45	"			
241	4480.52	0.274	3	50	50	"			
240	4480.69	6.33	2	30	70	"			
239	4481.04	0.369	2	40	60	"			
238	4481.21	0.329	3	65	35	"			
237	4481.38	2.4	2	40	60	"			
236	4481.54	0.524	3	50	50	"			
235	4481.71	1.13	3	50	50	"			
234	4481.88	0.212	3	50	50	"			
233	4482.08	0.954	4	100	0	parallel x-bed fn sd			

232	4482.25	1.05	5	95	5"			
231	4482.42	0.31	3	50	50"	bioturb sd/sh remnant lam - Terrebella		
230	4482.58	0.588	4	100	0"			
229	4482.75	0.787	3	65	35"			
228	4483.08	0.91	2	40	60"			
227	4483.25	0.459	2	30	70"			
226	4483.42	0.682	2	35	65"			
225	4483.58	0.991	4	95	5"	parallel lam. fn storm sd		
224	4483.75	0.545	3	60	40"	same as 178-181		
223	4484.06	0.728	2	30	70"			
222	4484.23	0.366	2	40	60"			
221	4484.4	0.677	3	60	40"			
220	4484.56	0.428	3	50	50"			
219	4484.73	0.355	3	50	50"			
218	4485	0.511	3	50	50"			
217	4485.17	0.193	2	40	60"			
216	4485.33	0.461	3	50	50"			
215	4485.5	0.299	2	25	75"			
214	4485.67	0.339	2	45	55"			
213	4486.05	0.47	3	60	40"			
212	4486.22	0.377	3	50	50"			
211	4486.39	0.167	3	50	50"			
210	4486.55	0.202	2	40	60"			
209	4487.03	0.356	3	60	40"	4487'		
208	4487.24	0.416	3	50	50"			
207	4487.44	0.488	3	60	40"			
206	4487.64	0.496	2	30	70"			
205	4487.85	0.544	2	40	60"	vertical Skolithos		
204	4488.05	0.222	3	60	40"			
203	4488.26	0.438	5	98	2"	same as 176-177		
202	4488.46	0.83	4	98	2"			
201	4488.66	1.01	2	55	45"	same as 178-181		
200	4488.87	0.127	2	35	65"			

199	4489.07	0.0927	2	20	80	"			
198	4489.28	0.188	2	30	70	"			
197	4489.48	0.442	5	95	5	same as 176-177			
196	4489.69	0.0294	4	100	0	"			
195	4489.89	0.463	2	40	60	same as 178-181			
194	4490.09	0.506	3	45	55	"			
193	4490.3	0.313	2	55	45	"			
192	4490.5	0.503	2	40	60	"			
191	4490.71	0.13	2	40	60	"			
190	4490.91	0.212	2	45	55	"			
189	4491.11	0.217	2	30	70	"			
188	4491.32	0.19	2	40	60	"			
187	4491.52	0.304	3	65	35	"			
186	4491.73	0.903	5	100	0	"			
185	4491.93	0.645	3	85	15	"			
184	4492.14	0.788	3	75	25	"			
183	4492.34	0.51	3	50	50	"			
182	4492.54	0.245	4	100	0	same as 176-177 storm beds			
181	4492.75	0.357	2	30	70	bioturb sd/sh lam (remnant)			
180	4492.95	0.684	2	25	75	"			
179	4493.16	0.412	2	40	60	"			
178	4493.36	0.425	3	60	40	"			
177	4493.56	0.665	4	100	0	Parallel lam to x-lam fn sd storm bed			
			4			Grades up fr. par. to x-bed like Bouma B-C			
176	4493.77	1.05	4	100	0	"			
175	4493.97	0.827	3	50	50	Same as 169			
174	4494.18	1.36	5	85	15	"			
173	4494.38	0.694	2	35	65	"			
172	4494.59	0.656	2	30	70	"			
171	4494.79	0.522	3	60	40	Skolithos			
170	4494.99	1.02	4	95	5	Parallel lam fn sd			
169	4495.2	0.35	3	50	50	bioturb sd/sh lam some remnant x-beds			
168	4495.4	0.287	2	25	75	Terebellina			

Machi Ross

167	4495.61	0.222	3	50	50"			
166	4495.81	0.22	2	30	70"			
165	4496.01	0.372	3	60	40"			
164	4496.42	0.109	2	40	60	Skolithos(?)		
163	4496.42	0.314	3	90	10	Thin rippled sd (F2a) within F3a interval		
162	4496.63	0.72	5	90	10	K measurements within the F2a		
161	4497	0.382	3	60	40"			
160	4497.17	0.221	3	50	50"			
159	4497.33	1.878	3	55	45"			
158	4497.5	1.39	2	30	70"			
157	4498.03	0.275	2	40	60	one thin F2a bed bet. 157-158		
156	4498.2	0.725	2	35	65"			
155	4498.36	0.161	2	30	70"			
154	4498.53	0.488	2	40	60"			
153	4498.7	9.4	2	20	80"			
152	4499.08	4.51	4	45	55"			
151	4499.25	0.485	2	45	55"			
150	4499.42	0.657	3	50	50"			
149	4499.58	0.353	3	50	50"			
148	4499.75	0.842	3	60	40"			
147	4500	0.299	2	40	60"			
146	4500.17	0.101	3	50	50"			
145	4500.33	0.45	5	60	40"			
144	4500.5	1.37	5	85	15"			
143	4500.67	0.333	2	45	55"			
142	4501	0.267	3	50	50	remnant ripple		
141	4501.17	0.834	3	60	40"			
140	4501.33	0.107	2	30	70	fine up unit 138-140		
139	4501.5	0.31	3	75	25"			
138	4501.67	1.42	5	95	5"			
137	4502	0.408	3	75	25"			
136	4502.17	0.46	3	55	45"			
135	4502.33	0.827	2	45	55	one thin F2a within this F3b interval		

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134	4502.5	0.46	2	45	55	"			
133	4502.67	2.92	2	45	55	"			
132	4503	1.82	5	95	5	parallel to x-bed fn sd (4503')			
131	4503.17	2.27	4	98	2	"			
130	4503.33	0.378	2	45	55	same as 115 - biot. sd/sh lam			
129	4503.5	0.504	3	55	45	"			
128	4503.67	1.3	4	95	5	" Skolithos			
127	4504	2.75	3	50	50	"			
126	4504.17	0.895	4	95	5	same as 51-62			
125	4504.33	0.109	5	90	10	"			
124	4504.5	0.498	5	95	5	"			
123	4504.67	2.78	5	95	5	"			
122	4504.83	0.0457	5	95	5	" 4505'			
122	4504.83	0.0457	5	95	5				
121	4505.1	0.116	5	97	3	"			
120	4505.27	1.24	5	100	0	"			
119	4505.44	2.58	5	100	0	"			
118	4505.6	1.11	5	95	5	"			
117	4505.77	1.1	3	65	35	bioturb sd/sh lam			
116	4506	0.914	3	85	15	"			
115	4506.17	1.71	3	85	15	"			
114	4506.33	3.31	5	95	5	same as 51-62			
113	4506.5	3.12	5	98	2	"			
112	4506.67	2.94	5	100	0	"			
111	4506.83	2.42	5	95	5	" large unidentified burrow			
110	4507.08	3.58	5	100	0	"			
109	4507.25	2.7	5	100	0	"			
108	4507.42	3.13	5	100	0	"			
107	4507.58	3.39	5	100	0	"			
106	4508	4.24	5	95	5	"			
105	4508.17	2.78	5	85	15	"			
104	4508.33	0.911	3	75	25	" Skolithos			
103	4508.5	0.374	3	75	25	"			

102	4508.67	2.69	5	95	5 "			
101	4508.83	1.68	5	100	0 "			
100	4509.08	3.26	5	95	5 "			
99	4509.25	3.59	5	85	15 "			
98	4509.42	4.31	5	100	0 "			
97	4509.58	2.33	5	85	15 "			
96	4509.75	2.82	5	95	5 "			
95	4510.04	2.7	5	98	2 " (4510')			
94	4510.21	4.12	5	80	20 bioturb sd/sh lam			
93	4510.38	3.52	5	80	20 "			
92	4510.54	2.31	5	95	5 " Skolithos			
91	4510.71	0.385	3	55	45 "			
90	4511	2.08	5	98	2 same as 51-62 biot fn sd w/wispy sh some			
89	4511.17	3.21	5	98	2 remnant x-beds			
88	4511.33	1.98	5	95	5 "			
87	4511.5	0.57	5	85	15 "			
86	4511.67	3.65	5	100	0 "			
85	4512	3.41	5	100	0 "			
84	4512.17	1.01	5	90	10 "			
83	4512.33	4.96	5	95	5 Occasional thin F3a/b. Too thin to resolve			
82	4512.5	5.8	5	90	10 "			
81	4513	3.33	5	80	20 " 4513'			
81	4513	3.33	5	80	20 "			
80	4513.17	3.71	5	98	2 "			
79	4513.33	1.94	5	100	0 "			
78	4513.5	4.08	5	97	3 "			
77	4513.67	3.95	5	100	0 "			
76	4514	0.746		80	20 bioturb sd/sh lam			
75	4514.17	1.15	3	90	10 "			
74	4514.33	1.2	3	90	10 "			
73	4514.5	2.7	5	95	5 "			
72	4514.67	1.04	2	40	60 "			
71	4515	1.21	3	55	45 "			

70	4515.17	3.23	5	95	5	same as 51-62		
69	4515.33	3.21	5	98	2	"		
68	4515.5	2.56	5	98	2	"		
67	4515.67	3.18	5	100	0	"		
66	4516.04	3.14	4	95	5	" Condrites		
65	4516.21	2.2	3	55	45	bioturb sd/sh lam-remnant lam		
64	4516.38	1.01	2	45	55	Skolithos		
63	4516.54	1.24	3	50	50	"		
62	4516.71	1.9	5	95	5	burrowed fn sd w/wispy sh some remnant		
61	4517.04	2.84	5	95	5	x-beds		
60	4517.21	2.33	5	98	2	"		
59	4517.38	1.88	3	80	20	"		
58	4517.54	1.67	3	85	15	" Condrites		
57	4517.71	2.78	5	100	0	"		
56	4517.88	3.46	5	97	3	"		
55	4518.03	2.08	5	80	20	"		
54	4518.2	2.34	5	98	2	"		
53	4518.36	1.46	3	65	35	" Skolithos		
52	4518.53	2.04	5	98	2	"		
51	4518.96	1.7	5	95	5	"		
50	4519.13	1.2	5	90	10	x-beds,fn sd		
49	4519.29	1.13	5	95	5	"		
48	4519.46	1.07	3	65	35	sharp contact bet 45-46 w/overlying sd		
47	4519.63	1.88	3	70	30	Some load struct. or eros. base of sd into under-		
46	4520	1.06	3	90		lying sh at contact Basal sd=burrowed fn sd w/silt		
45	4520.17	1.16	1	5	95	Gray-blk org-rich blot. sh		
44	4520.33	2.42	1	5	95	"		
43	4520.5	0.715	1	5	95	"		
42	4520.67	0.226	1	7	93	" flattened Terebellina(?)		
41	4520.83	0.739	1	7	93	"		
40	4521.08	0.253	1	7	93	"		
39	4521.25	0.168	1	7	93	"		
38	4521.42	0.17	1	7	93	"		

37	4521.58	0.041	1	7	93	"			
36	4521.97	0.257	1	10	90	"			
35	4522.14	3.17	1	7	93	"			
34	4522.3	0.56	1	7	93	"			
33	4522.47	0.184	1	7	93	"			
32	4522.64	0.691	1	7	93	"			
31	4522.8	0.049	1	7	93	"			
30	4522.97	1.79	1	7	93	"			
29	4523.14	0.0363	1	7	93	"			
28	4523.3	0.016	1	7	93	"			
27	4523.47	0.361	1	7	93	"			
26	4523.64	0.0429	1	7	93	"			
25	4523.8	0.541	1	7	93	"			
24	4523.97	0.0172	1	7	93	"			
23	4524.14	0.052	1	7	93	"			
22	4524.3	0.0333	1	7	93	"			
21	4524.47	0.1	1	7	93	"			
20	4524.64	0.0376	1	7	93	"			
19	4524.8	0.019	1	7	93	" possible Terebellina			
18	4524.97	0.535	1	7	93	"			
17	4525.14	0.0548	1	7	93	" shell fragments of large "floater" fossil			
16	4525.3	0.38	1	7	93	Inoceramos well preserved calcite cement			
15	4525.47	0.0667	1	7	93	in vertical orientation			
14	4525.64	0.0405	1	7	93	"			
13	4525.8	0.126	1	7	93	Inoceramus frags.			
12	4525.97	0.119	1	7	93	"			
11	4526.14	0.323	1	5	95	"			
10	4526.3	0.0883	1	5	95	"			
9	4526.47	0.037	1	5	95	"			
8	4526.64	0.14	1	5	95	"			
7	4526.8	0.0426	1	5	95	"			
6	4526.97	0.0364	1	5	95	"			
5	4527.14	0.429	1	5	95	"			

4	4527.3	0.05	1	5	95	"			
3	4527.47	0.294	1	5	95	"			
2	4527.64	0.257	1	5	95	"			
1	4527.97	0.0672	1	5	95	"			
0	4529.04	0.207	1	5	95	Base of core @ 4529.3'			
Facies 1 = Bioturbated mudstone (to sandy mudstone) shelf facies									
Facies 2 = Burrowed to biotubated sandy mudstone									
(more sand and remnant laminations than 1)									
Facies 3 = Burrowed to bioturbated muddy sandstone									
Facies 4 = Planar to slightly x-bedded w/o burrows									
Facies 5 = Ripple-bedded sandstone, minor burrows									

TABLE 5-2

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Amoco Prod. Co. Vern Marshall #1 4N-65W-Sec. 32												
2	samples every 6"												
3													
4	Top Depth	Depth (ft)	KI	Facies	H Perm (md)	V Perm (md)	Por (%)	So (%)	Sw (%)	%sd	%sh	Lithology	
5	165	4590	0.014	1						5	95	more highly lam sh w/sd lam	
6	164		0.036	1						5	95	not as burrowed as below	
7	163	4591	0.057	1						10	90	"	
8	162		0.522	1						20	80	"	
9	161	4592	0.029	1						10	90	"	
10	160		0.133	1						15	85	"	
11	159	4593	0.189	1						15	85	"	
12	158		0.141	1						25	75	"	
13	157	4594	0.324	1						15	85	"	
14	156		0.13	1						30	70	"	
15	155	4595	0.033	1						35	65	"	
16	154		0.33	1						25	75	"	
17	153	4596	0.595	1						15	85	"	
18	152		0.043	1						10	90	"	
19	151	4597	0.342	1						10	90	"	
20	150		0.088	1						10	90	"	
21	149	4598	0.04	1						10	90	"	
22	148		0.139	1						10	90	"	
23	147	4599	0.325	1						50	50	"	
24	146		0.087	1						10	90	"	
25	145	4600	0.067	1						20	80	"	
26	144		0.027	1						10	90	"	
27	143	4601	0.079	1						10	90	"	
28	142		0.053	1						10	90	"	
29	141	4602	0.359	1						20	80	"	
30	140		0.022	1						10	90	"	
31	139	4603	0.0146	1						10	90	"	
32	138		0.237	1						15	85	"	
33	137	4604	0.093	1						10	90	"	
34	136		0.014	1						10	90	"	
35	135	4605	0.056	1						10	90	"	
36	134		0.015	1						10	90	"	
37	133	4606	0.028	1						20	80	"	
38	132		0.041	1						30	70	"	
39	131	4607	0.139	1						30	70	"	
40	130		0.501	1						10	90	"	
41	129	4608	0.067	1						10	90	"	
42	128		0.443	1						60	40	"	
43	127	4609	0.326	1						30	70	"	
44	126		0.026	1						40	60	"	
45	125	4610	0.138	1						15	85	"	
46	124		0.095	1						10	90	"	
47	123	4611	0.598	2	0.22	0.08	12.7	0	80.4	40	60	Biot. sd/sh lam	
48	122		0.108	2						40	60	"	
49	121	4612	0.195	3	0.18	0.06	12.2	0	79.1	55	45	"	
50	120		0.158	3						50	50	"	
51	119	4613	0.19	3	0.2	0.09	14	0	79.1	50	50	"	
52	118		0.409	2						40	60	"	
53	117	4614	0.204	2	0.18	0.07	12.5	0	79.2	40	60	"	
54	116		0.315	2						30	70	"	
55	115	4615	0.283	2	0.17	0.08	12.9	0	81.8	30	70	"	
56	114		0.058	2						30	70	"	
57	113	4616	0.391	2	0.19	0.09	12.7	0	79.7	30	70	"	
58	112		0.4	2						30	70	"	
59	111	4617	0.268	2	0.15	0.07	11.7	0	82.6	30	70	"	

61	109	4618	0.105	2	0.28	0.08	11.2	0	79.1	40	60	"
62	108		0.761	3						50	50	"
63	107	4619	0.931	2	0.15	0.07	11.1	0	78.1	40	60	"
64	106		0.287	3						55	45	"
65	105	4620	0.242	3	0.23	0.1	12.6	0	66.5	50	50	"
66	104		0.169	2						40	60	"
67	103	4621	0.263	3	0.43	0.11	12.8	0.8	72.5	50	50	"
68	102		0.106	3						60	40	"
69	101	4622	0.134	3	0.13	0.06	11.6	1.6	79.8	65	35	"
70	100		0.224	3						85	15	"
71	99	4623	0.28	3	0.23	0.1	12.3	0.8	69.2	85	15	"
72	98			3						75	25	"
73	97	4624	0.384	3	0.2	0.1	13.1	1	51.2	60	40	"
74	96		0.211	3						60	40	"
75	95	4625	0.192	3	0.29	0.09	12.6	3.4	53.8	50	50	"
76	94		0.35	3						55	45	"
77	93	4626	0.359	2	0.2	0.08	11.7	2	75.5	35	65	"
78	92		0.535	3						50	50	"
79	91	4627	0.277	2	0.17	0.09	11.8	1.3	62.4	40	60	"
80	90		0.532	3						55	45	"
81	89	4628	0.709	2	0.13	0.09	10.2	4.5	58.7	40	60	"
82	88	4629	0.325	2	0.18	0.11	12.6	4.5	55	35	65	"
83	87		0.287	3						60	40	"
84	86	4630	0.659	2	0.23	0.1	12.2	1.6	69.9	40	60	"
85	85		0.569	3						60	40	"
86	84	4631	0.221	3	0.16	0.09	11.2	1.1	68.2	50	50	"
87	83		0.2	2						40	60	"
88	82	4632	0.03	4	0.22	0.09	11.9	5.8	83.4	100	0	" 2" thick v fm sd bed
89	81		0.392	3						60	40	"
90	80	4633	0.602	3	0.27	0.08	10.2	5.3	45.1	65	35	"
91	79		0.632	2						45	55	"
92	78	4634	0.481	2	0.23	0.016	12.7	4.3	56.4	40	60	"
93	77		0.727	3						70	30	"
94	76	4635	0.8	3	0.32	0.16	13.2	4.3	53.1	55	45	"
95	75		0.868	3						60	40	"
96	74	4636	0.729	3	0.37	0.31	12.3	7.6	54.3	80	20	"
97	73			2						45	55	"
98	72	4637	0.486	3	0.26	0.08	11.9	6.8	63.2	55	45	"
99	71		0.616	3						80	20	"
100	70	4638	1.06	3	0.49	0.1	12.5	7	37.2	50	50	"
101	69		1.07	2						45	55	"
102	68	4639	1.2	4	0.22	0.42	12.2	1.3	63.6	100	0	" Parallel lam sd
103	67		1.47	3						65	35	"
104	66	4640	0.98	2	0.27	0.13	13.1	6.2	63.4	35	65	"
105	65		1.21	3						90	10	"
106	64	4641	1.06	2	0.23	0.1	11.1	6.6	45.5	30	70	"
107	63		0.815	3						50	50	"
108	62		0.968	3	0.33	0.09	12.2	5.3	68.7	60	40	"
109	61	4642	0.347	2						40	60	"
110	60		1.44	2	0.19	0.14	12.4	6.4	58.3	40	60	"
111	59	4643	1.13	3						70	30	"
112	58		0.568	3	0.54	0.1	12.7	6.3	61.2	85	15	"
113	57	4644	1.02	2						40	60	"
114	56		0.912	3	0.24	0.15	13.4	5.4	62.9	60	40	"
115	55	4645	0.472	3						55	45	"
116	54		0.289	3	0.25	0.1	11.2	4.5	61.8	50	50	"
117	53	4646	0.634	3						65	35	"
118	52		0.535	2	1.2	0.1	12.5	4.3	55.7	30	70	"

	A	B	C	D	E	F	G	H	I	J	K	L	M
119	51	4647	0.539	3						50	50		
120	50		2.37	3	0.52	0.2	14	7.2	38.5	85	15	Parallel lam fn sd	
121	49	4648	0.562	4						100	0		
122	48		1.19	3	0.57	0.26	14.3	5.8	50.3	85	15	Bioturb. sd/sh lam	
123	47	4649	1.15	3						90	10		
124	46		1.06	3	0.52	0.11	14	5.1	54.1	85	15		
125	45	4650	0.915	3						80	20		
126	44		0.84	5	0.55	0.11	12.5	10.4	38.3	95	5	Climbing rip. sd	
127	43		1.25	3						95	5	Biot. sd/sh lam	
128	42	4651	0.43	3	0.49	0.11	12	6.4	48.1	85	15		
129	41		4.63	3						85	15		
130	40	4652	1.16	5	1.1	0.33	15	6.6	61.4	100	0	x-lam fn sd	
131	39		1.19	3						85	15	Biot. sd/sh lam	
132	38	4653	2.32	2	1.1	0.29	14.5	8	35.6	35	65		
133	37		6.41	3						80	20		
134	36	4654	0.553	4	0.41	0.09	13.8	4.3	63.2	100	0	Parallel lam fn sd	
135	35		1.74	2						35	65	Biot. sd/sh lam	
136	34			3	0.52	0.25	13.6	4.7	44.1	70	30		
137	33	4655	0.37	3						95	5	parallel lam, Same as 0-28	
138	32		0.744	3	0.42	0.1	13.6	5.1	43.9	90	10		
139	31	4656	1.32	3						85	15		
140	30		0.874	3	0.4	0.2	14.2	6.2	54.5	55	45	Biot. sd/sh lam	
141	29	4657	1.38	2						35	65	Bioturb. sd/sh lam	
142	28		1.08	4	1.9	0.97	15.2	7.7	35.4	90	10	Fn sd, same as 0-9	
143	27	4658	1.45	4						95	5		
144	26		1.84	4	1.1	0.5	14.3	13.5	39.9	90	10		
145	25	4659	1.47	4						85	15		
146	24		1.02	4	1.8	1.5	14.3	11.5	31.4	90	10		
147	23	4660	1.44	4						85	15	some parallel lam.	
148	22		1.39	4	0.46	0.1	12.9	11.5	37.4	85	15		
149	21	4661	1.63	4						95	5	remnant parallel lam	
150	20		0.517	4	1.5	0.15	14.8	11.8	34.7	95	5		
151	19	4662	2.57	4						80	20		
152	18		2.36	4	2.4	0.81	14.8	13.5	36	95	5		
153	17	4663	2.11	4						85	15		
154	16		1.53	4	0.43	0.13	13.4	10.5	40.8	85	15		
155	15	4664	1.84	4						95	5		
156	14		1.15	4	2.9	0.62	15	12.2	35.9	90	10		
157	13	4665	2.46	4						90	10	60deg closed fract	
158	12		2.75	4	1.2	0.36	15.2	10	45	90	10		
159	11	4666	2.22	4						90	10		
160	10		2.03	4	0.57	0.09	11.8	13	34.7	100	0	Bouma B-C parallel lam to x	
161	9	4667	1.94	4						65	35	Mainly ss b eds w/some sh la	
162	8		2.76	4	1.2	0.6	14.2	4.1	49.2	50	50	Bioturb. remnant X-bed (above	
163	7	4668	1.3	4						95	5	shelf sh that is pres. In other	
164	6		1.8	4	0.32	0.16	11.2	23.3	48.4	70	30		
165	5	4669	2.32	4						90	10		
166	4		1.99	4	0.79	0.64	13.4	13.3	37.8	80	20		
167	3	4670	2.39	4						70	30		
168	2		1.55	4	0.29	0.16	12.2	12.3	41.6	80	20		
169	1	4671	0.681	4						55	45		
170	0		1.22	4						40	60	Base of core	
171		4672	0.855										
172			0.354										
173		4673											
174													
175	Facies 1 = Bioturbated mudstone (to sandy mudstone) shelf facies												
176	Facies 2 = Burrowed to bioturbated sandy mudstone												
177	(more sand and remnant laminations than 1)												

[illegible]

TABLE /-1

VERNM.XLS

Sample	Depth	Sorting	Carbonate	Clay	Visual per	visual por	pres. decay	facies	plug K	plug por.	plug Sw	%sd	
19	4627.29	1	3.5	7	9.5	12	0.28	2	0.17	11.8	62.4	40	
18	4633.25	1	4.5	6	8.5	11	0.6	2	0.27	10.2	45.1	65	
17	4637.9	1	3.5	7	9.5	12	1.06	2	0.49	12.5	37.2	50	
14	4650.92	1.5	3.5	6.5	9.5	12.5	0.43	2	0.49	12	48.1	85	
10	4661.84	1.5	3.5	6.5	9	11.5	0.52	4	1.5	14.8	34.7	95	
6	4665.88	1	3.5	6	9	12	2.75	4	1.2	15.2	45	90	
5	4665.96						2.75	4	1.2	15.2	45	90	
4	4668.08	1	3.5	6.5	8.5	12	1.8	4	0.32	11.2	48.4	70	
3	4669.67	1	4	6.5	9	12	1.99	4	0.79	13.4	37.8	80	
2	4671.67	1	4	6	8.5	12	1.22	4				80	
1	4672.04	2	3.5	6.5	9	11	0.86	4				80	
		Sorting	CaCO3 ce	Clay Conte	visual v/h p	visual por.		Facies 1 = Bioturbated mudstone (to sandy mudstone) shelf facies					
		1=well sorte	3=<5%	6=very little	8.5=highv/h	10.5=nil		Facies 2 = Burrowed to bioturbated sandy mudstone					
		1.5=mod sor	3.5=5-15%	6.5=thin lay	9=app. =v/h	11=<5%		(more sand and remnant laminations than 1)					
		2=poor sort	4=>15-25%	and clay cl	9.5=low v/h	11.5=5-10%		Facies 3 = Burrowed to bioturbated muddy sandstone					
			4.5=25-40%	7=abundant		12=10-15%		Facies 4 = Planar to slightly x-bedded w/o burrows					
			5=>40% car	7.5=mudrock		12.5=>15%		Facies 5 = Ripple-bedded sandstone, minor burrows					
			supported gns					Facies 6 = Mudstone/sandstone clasts in mud/sd. matrix					
								Debris flow bed					

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Sample #	Depth	SORTING	CARBONATE	CLAY	visual perm	visual por.	FACIES	PERCENT SD	PRES DECAY	Comments		
TC-1	4441.5	1.5	4	6.5	9	11.5	5	85	1.26	1-2cm thick sst. in shale		
TC-3	4446.3	1.5	4	6.5	9	11.5	5	90	1.52	small scale x-beds		
TC-4	4448.4	1.5	3.5	6.5	9	11.5	3	65	2.17	mixed sd/sh		
TC-5	4450.9	1.5	3.5	6.5	9	11.5	3	60	3.06	5cm x-bed sd		
TC-6	4453.8	1.5	4	6.5	9.5	11.5	2	35	0.95	lam. fn sd		
TC-7	4458	1.5	3.5	6.5	9	11	1	20	0.54	sandy mudstone		
TC-8	4457.8	2	3.5	7.5	9	10.5	1	10	0.36	2cm above bentonite		
	4479.2	1.5	4.5	6.5	8.5	10.5	2	10	0.78	2-3cm ss layer (Ca4-5)		
TC-9	4489	2	4.5	7	9.5	10.5				carb concretion		
		Sorting	CaCO3 ce	Clay Conte	visual v/h p	visual por.	Facies 1 = Bioturbated mudstone (to sandy mudstone) shelf facies					
		1=well sorte	3=<5%	6=very little	8.5=highv/h	10.5=nil	Facies 2 = Burrowed to bioturbated sandy mudstone					
		1.5=mod sor	3.5=5-15%	6.5=thin laye	9=app. =v/h	11=<5%	(more sand and remnant laminations than 1)					
		2=poor sort	4=>15-25%	and clay cl	9.5=low v/h	11.5=5-10%	Facies 3 = Burrowed to bioturbated muddy sandstone					
			4.5=25-40%	7=abundant		12=10-15%	Facies 4 = Planar to slightly x-bedded w/o burrows					
			5=>40% car	7.5=mudrock		12.5=>15%	Facies 5 = Ripple-bedded sandstone, minor burrows					
							Facies 6 = Mudstone/sandstone clasts in mud/sd. matrix					
							Debris flow bed					

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TABLE 7-3

BURKECO.XLS

Sample	Depth	Sorting	Carbonate	Clay	VISUAL PER	VISUAL POR	Comments			
B1	4455.8	1	4	6.5	9	11.5	small scale x-bed, 3-4 cm thick in mudstone			
B2	4461.7	1.5	4.5	7	9	10.5	Thin lam. fn. sd			
B3	4465.3	1.5	4.5	6.5		10.5	Contact b/t good reservoir sd. & mudstone			
B4	4470.1	1	3.5	6.5	8.5	12.5	good sand			
B5	4476.5	1.5	3.5	6	8.5	12	massive lam fn sd			
B6	4481.5	2	3.5	7	9.5	10.5	mixed mud and sd			
B7	4485.9	1.5	4	6	9	11	reservoir sd fining upward			
B8	4496.8	1.5	4.5	6.5	9.5	11	parallel lam sd			
B9	4502.3	1.5	4.5	6.5	9	11	carb. cemented sd			
B10	4505.3	1.5	4	6.5	9	11	mixed biot. sd/mud			
B11	4513.8	2	4	7	9	10.5	mudstone			
		Sorting	CaCO3 ce	Clay Conte	visual v/h p	visual por.				
		1=well sorte	3=<5%	6=very little	8.5=highv/h	10.5=nil				
		1.5=mod sor	3.5=5-15%	6.5=thin lay	9=app. =v/	11=<5%				
		2=poor sort	4=>15-25%	and clay cl	9.5=low v/h	11.5=5-10%				
			4.5=25-40%	7=abundant		12=10-15%				
			5=>40% car	7.5=mudrock		12.5=>15%				
			supported gns							

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Sample	Depth	Sorting	Carbonate	Clay	visual perm	visual por.	Facies	Percent Sd	PRES DECAY	Comments		
T1	4406.5	1.5	3.5	6.5	9.5	11.5	3	60	0.91	biot. mixed facies		
T2	4407	1	3.5	6	8.5	12	4	100	1.43	pure well sorted carb. sd?		
T3	4408	1	4	6	9	11.5	4	98	1.58	top well sorted carb. sd		
T4	4410.7						3	60	1.11	rippled fn sd and clay, no thin sect.		
T5	4413	1.5	4	7	9.5	11	2	45	0.85	thin ss layer		
T6	4417	1.5	4	6.5	9.5	11.5	5	95	1.64	5cm thick ss bed		
T7	4422.7	1.5	3.5	6.5	9.5	11.5	6	60	0.8	rip-up clast facies		
T8	4428.4	1.5	4	6.5	9.5	11.5	6	60	0.89	pure well-sorted sd clast?		
T9	4434.5	1.5	3.5	6.5	9.5	12	3	70	4.46	good reservoir sd		
T10	4440	1.5	3.5	6.5	9	12	5	95	2.46	good relative thick reservoir sd		
T11	4448.5	1.5	4	6.5	9	11.5	2	45	4.21	biot. muddy facies		
T12	4451.6	2	3.5	7.5	9	10.5	1	15	2.28	mudstone, muddy ss/siltstone		
T13	4452.5	2	4.5	6.5	9	10.5	1	85	1.66	fn grnd. carb. mudstone		
		Sorting	CaCO3 ce	Clay Conte	visual v/h p	visual por.	Facies 1 = Bioturbated mudstone (to sandy mudstone) shelf facies					
		1=well sorte	3=<5%	6=very little	8.5=high v/h	10.5=nil	Facies 2 = Burrowed to bioturbated sandy mudstone					
		1.5=mod sor	3.5=5-15%	6.5=thin laye	9=app. =v/h	11=<5%	(more sand and remnant laminations than 1)					
		2=poor sort	4=>15-25%	and clay cl	9.5=low v/h	11.5=5-10%	Facies 3 = Burrowed to bioturbated muddy sandstone					
			4.5=25-40%	7=abundant		12=10-15%	Facies 4 = Planar to slightly x-bedded w/o burrows					
			5=>40% car	7.5=mudrock		12.5=>15%	Facies 5 = Ripple-bedded sandstone, minor burrows					
			supported gns				Facies 6 = Mudstone/sandstone clasts in mud/sd. matrix					
							Debris flow bed					

TABLE 8-1

Percent Sand, Facies, and Permeability Data for Five Cores

	A	B	C	D	E	F	G	H	I	J
1	Well	Facies	n	Aver. %Sd.	Aver. K	<0.1md	0.1-0.5md	0.5-1md	1-5md	>5md
2										
3	Vern Marshall	1	41	18	0.15	23	15	3	0	0
4		2	32	37	0.62	1	17	7	7	0
5		3	54	67	0.84	0	22	19	12	1
6		4	33	85	1.6	1	0	4	28	0
7		5	2	98	1	0	0	1	1	0
8										
9	Machii Ross	1	46	6	0.04	19	17	6	4	0
10		2	77	38	0.22	1	35	25	14	2
11		3	83	60	0.87	0	33	25	25	0
12		4	18	94	1.28	1	2	6	7	0
13		5	75	93	2.28	4	7	3	60	1
14										
15	Sotexco	1	14	27	2.9	0	0	0	13	1
16		2	16	39	1.9	0	0	2	14	0
17		3	35	64	1.5	0	1	10	24	0
18		4	9	97	3	0	0	0	7	2
19		5	19	91	1.7	1	3	2	13	0
20		6	13	48	1.5	0	0	2	11	0
21										
22	Moser	1	72	13	1	0	20	25	27	0
23		2	10	40	2.1	0	0	2	8	0
24		3	12	64	2	0	0	0	12	0
25		4	0							
26		5	3	87	1.5	0	0	0	3	0
27										
28	Eckhardt	1	45	7	0.7	4	19	16	6	0
29		2	82	32	1	0	21	32	29	0
30		3	104	64	1	1	23	40	40	0
31		4	53	87	1.1	7	8	6	32	0
32		5	33	88	1.2	2	9	6	15	1
33										
34	Facies 1 = Bioturbated mudstone (to sandy mudstone) shelf facies									
35	Facies 2 = Burrowed to bioturbated sandy mudstone									
36	(more sand and remnant laminations than 1)									
37	Facies 3 = Burrowed to bioturbated muddy sandstone									
38	Facies 4 = Planar to slightly x-bedded w/o burrows									
39	Facies 5 = Ripple-bedded sandstone, minor burrows									
40	Facies 6 = Mudstone/sandstone clasts in mud/sd. matrix									
41	Debris flow bed									

TABLE 8-2

Summary Data for Percent Sand
and Permeability by Facies for Five Cores

	A	B	C	D	E	F	G	H	I
1		n	Aver. %Sd.	Aver. K	<0.1md	0.1-0.5md	0.5-1md	1-5md	>5md
2	Facies 1 aver	218	12	0.59	46	71	50	50	1
3									
4	Facies 2 aver	217	36	0.78	2	73	68	72	2
5									
6	Facies 3 aver	288	63	1.03	1	79	94	113	1
7									
8	Facies 4 aver	111	88	1.43	9	10	16	80	2
9									
10	Facies 5 aver	132	91	1.89	7	19	12	92	2
11									
12	Facies 6 aver	13	48	1.5	0	0	2	11	0
13									
14	Facies 1 = Bioturbated mudstone (to sandy mudstone) shelf facies								
15	Facies 2 = Burrowed to bioturbated sandy mudstone								
16	(more sand and remnant laminations than 1)								
17	Facies 3 = Burrowed to bioturbated muddy sandstone								
18	Facies 4 = Planar to slightly x-bedded w/o burrows								
19	Facies 5 = Ripple-bedded sandstone, minor burrows								
20	Facies 6 = Mudstone/sandstone clasts in mud/sd. matrix								
21	Debris flow bed								

APPENDIX B

Three-Dimensional Seismic Reservoir Characterization of Lambert Field, Denver Basin, Colorado

by

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Introduction

Hambert field is located in Weld County, Colorado, approximately five miles south of the city of Greeley, in the central portion of the Denver Basin. The Upper Cretaceous Terry Sandstone at Hambert produces oil and gas at an approximate depth of 4500 feet (1370 m). The Terry consists of linear sand ridges, elongated in the northwest-southeast direction. The sand ridges are encased and inter-stratified by marine shale. The gross thickness of the Terry is approximately 150 feet (46 m). The Terry can be subdivided into several major sedimentary facies (Al-Raisi, 1996) with the best developed reservoir being a sand unit near the base which is approximately 60 feet (18 m) thick. In the reservoir unit, porosities range from 12% to 14%, and permeabilities of less than 0.2 md to 3 md. Permeabilities are low due to clay plugging of the sands. The oil is normally 50°-60° API with a Gas Oil Ratio (GOR) of 10,000-20,000 SCF/STB (McKinnie, 1993).

Available Seismic Data

Amoco Production Company selected Hambert field to test the application of seismic lithology prediction methods. Three-dimensional (3-D) P-wave and S-wave seismic surveys were acquired by Amoco over the eastern edge of Hambert field (December, 1981 - March, 1982). The surveys had identical acquisition geometries, with an extent of approximately 3 square miles (8 km²). The P-wave survey was acquired first using vertical-component vibrators and geophones. The S-wave survey was acquired next with horizontal-component vibrators and geophones. All S-wave source and receiver motion was restricted to the east-west direction.

After completing the 3-D acquisition, 2-D P-wave and S-wave seismic lines were acquired. These lines were approximately 10 miles (16 km) in length and oriented in a north-south direction. They were acquired to tie the 3-D surveys to a well six miles to the north that had been logged with a full-waveform sonic tool. The S-wave data was once again acquired with all S-wave source and receiver motion restricted to the east-west direction.

History of Concepts and Interpretations

Davis (1974) completed a seismic investigation of faults in the subsurface within a 20-township area surrounding Hambert field. This study was later published in a volume on seismic stratigraphy (Weimer and Davis, 1977). A model was presented for the control of stratigraphic systems and structural styles by recurrent movement on deep-seated basement-controlled faults. The study emphasized the association between tectonics and sedimentation and the interrelation between structure and stratigraphy that controls reservoir distribution in the subsurface.

Davis (1985) further published on structural styles in the Boulder and Greeley areas associated with recurrent movement on basement faults. This paper presented the concept that strike-slip motion on basement faults could introduce listric or curved plane faults in stratigraphic intervals that were "tectonically sensitive." Faults and folds create curvature, extension and potential of fractured reservoirs in proximity to petroleum source beds.

During the time interval from the mid-1970's until the mid-1980's as these new structural models and concepts were being utilized, increased stratigraphic information was becoming available from seismic data (Davis, 1984). Technologies have led to greater seismic resolution

which has increased stratigraphic exploration. Increasing the frequency content and bandwidth of seismic data to facilitate seismic-stratigraphic exploration is an evolutionary process in the seismic industry that started in earnest in the mid-1970's and is still going on.

Regional Structural Interpretation

Interpreted structural features are shown on seismic lines extracted from the 3-D seismic volumes (Figures 1 and 2). Basement controlled faults project from the basement (near 2.2 seconds on the P-wave seismic volume) upwards into the sedimentary section. These faults branch outward from a near-vertical fault or fault zone at depth to a series of faults within the sedimentary section. The branching is relatively narrow at depth but increases in lateral dimension in the shallow sedimentary section. High angle faulting is the dominant style of deformation within the basement, whereas both faults and folds occur in the sedimentary strata.

Minor folds and flexures in the sedimentary section formed in response to the deep-seated fault movements. Fault curvature induces folds. Some faults in the sedimentary section appear detached from the basement faults. These faults are listric (curved plane) and flatten into detachment or decollement zones. The pattern of fault curvature toward the major basement-controlled faults indicates a "cause and effect" mechanism that links these faults together, although individual fault planes themselves may be unattached.

Basement consists of a Precambrian igneous and metamorphic complex. In a rock mechanics sense, the basement in the Denver basin behaves in a brittle manner, whereas the overlying sedimentary section exhibits ductile behavior. The mechanical strength of rocks affects the way they deform. Differences in fault styles and attitudes as displayed reflect these fundamental differences in mechanical properties of the rock.

Detachment of decollement zones for Cretaceous listric normal faults also constitute major source rock intervals in the Denver basin. The Graneros Shale and the lower Pierre act as major decoupling zones or "shock absorbers" in the stratigraphic system and reflect periodic recurrent movement on the basement faults. Ductility along with reduced effective stress during tectonism, overpressuring and hydrocarbon generation created these decoupling zones. Their identification may be used in hydrocarbon exploration in the basin. Patterns of listric faulting may suggest basement fault zones when other criteria to establish the deep faulting is absent.

Basement-controlled faults branch upwards into the sedimentary section. This branching produces "flower structures" indicative of strike-slip tectonics (Christie-Blick and Biddle, 1985 and Harding, 1983). Flower structures are formed by the upward and outward spreading of strike-slip faults exhibiting normal or reverse separation and displacement. In map view, these structures form parallel and adjacent to the main faults. Flower structures are important in petroleum exploration and development. Hydrocarbon traps can occur in folds and flexures induced by the faults, in fault blocks, and in en echelon listric and related fault structures flanking the main strike-slip fault zone.

Basement-controlled faults in the Denver basin exhibit recurrent movement (Weimer, 1980). Evidence for recurrent movement includes isopach (thickness) and isochron (seismic time interval) changes and the different levels of listric normal faults. Clearly, some of the basement-controlled faults have had relatively "young" movement as disruptions and fault offsets occur at even the shallowest reflectors. The absolute age of youngest movement is uncertain, however. Some stream drainages in the area and other surface features appear to be coincident with the position

of faults in the subsurface. Movement on these faults may have continued episodically during the Tertiary and may even exhibit Quaternary movement. The Denver/Derby earthquakes that occurred in the mid-1960's are evidence that the basement is still under stress. These earthquakes were generated by strike-slip motion along a fault or fault zone in the vicinity of the Rocky Mountain Arsenal well (Healy et al., 1968). A deep well was drilled on the Rocky Mountain Arsenal in 1961 to dispose of contaminated waste water. Pressure injection of waste water into fractured Precambrian rock began in 1962. The fluid injection increased pore pressure which reduced effective stress and facilitated movement along a northwest trending fault zone.

Movement of basement-controlled faults occurred in Late Cretaceous time (Davis, 1974, and Weimer and Davis, 1977). Listric normal faults are present in the Laramie/Fox Hills/upper Pierre interval, the middle Pierre and the basal Pierre/Niobrara to Graneros interval. These three dominant intervals or levels of listric normal faults coincide with geologic episodes of recurrent movement on basement faults (Davis, 1985).

Some basement-controlled faults appear to cut the J Formation but do not extend much farther upward which indicate active movement during or shortly after J time in the Early Cretaceous but no younger reactivation. Clearly, not all faults have exhibited the same timing of movement or reactivation. Subsurface well control and seismic data suggest that fault block movement occurred during Terry time and controlled stratigraphic facies changes in the Terry.

The seismic data indicate that isopach and isochron variations occur across some faults in the Paleozoic Fountain Formation and older stratigraphic intervals immediately overlying the basement. These changes indicate Paleozoic movement on some basement-controlled faults. Recurrent movement on basement faults produces faults, folds and flexures in subsurface sedimentary strata. These structures can produce open fractures leading to fracture enhanced production from reservoirs (Davis and Benson, 1992). To sustain open fractures in reservoirs stress relief must occur, otherwise fractures close. Stress relief occurs by tectonic movement, local salt dissolution (Davis and Lewis, 1990), local overpressuring and possible other mechanisms (Gretener and Davis, 1992). The potential for fracture enhanced reservoir production occurs within Lambert field especially within the Terry Formation, but other stratigraphic intervals, including the Niobrara, contain potential as well (see Weimer, 1992).

Weimer (1978) demonstrated in a regional study that basement fault block movement influenced relative sea level change during the Cretaceous J to Niobrara time interval. Sonnenberg and Weimer (1981) compiled a regional study indicating recurrent fault block movement influenced sedimentation at various geologic time periods in the Denver basin. All these data, including seismic, point to the importance of basement fault control on sedimentation.

Reservoir Characterization

The Terry Sandstone is expressed as a low amplitude seismic reflection on both the P-wave and S-wave data (Figures 1 and 2). The Terry Sandstone, Niobrara, "J" Sandstone, and several seismic "markers" were interpreted on the seismic data and were integrated into a structural interpretation of the area. The Terry has limited structural expression in the area of the seismic data. The majority of the structural variation is related to faults which intersect the reservoir. Faults are imaged on both the P-wave and S-wave seismic data; however, the S-wave data image the majority of the faults with greater clarity. Fault mapping on both P-wave and S-wave seismic data shows dominant northeast-southwest faulting with throws of 10 to 50 feet (3 to 15 m) at the

reservoir level (Figure 3). A large fault occurs in the southern portion of the 3-D seismic area and is well imaged on both the P-wave and S-wave data. Figure 3 shows the fault system as it cuts the reservoir while Figure 4 shows the location at which it intersects the deeper J sandstone interval. A time slice displayed from the P-wave seismic volume (Figure 5) shows the abrupt truncation of the reservoir due to the main fault. A cube volume display of the S-wave seismic data (Figure 6) allows a greater understanding of the relation of faulting to the Terry reservoir. The main fault which cuts the reservoir is part of a fault complex that exhibits a negative flower structure associated with strike-slip faulting in the Denver Basin. This fault style was first interpreted on 2-D seismic data from Lambert field by Davis (1985). The importance of this fault style is reservoir compartmentalization by fault offset and by diagenetic events associated with these faults. Primary porosity and permeability are occluded along these faults by diagenetic overprints related to calcite cementation. Clays can also be an important factor in causing sealing conditions associated with these fault systems. Recognition of faults and sealing conditions associated with these faults is of primary significance in reservoir characterization.

Ruckgaber (1988) demonstrated techniques of lithology estimation on the 2-D, P-wave and S-wave seismic data in Lambert field. Using velocity information (V_P/V_S), Ruckgaber was able to create lithology information which was in agreement with existing geologic information. The low data quality of the 3-D, P-wave and S-wave seismic data limits the applicability of these techniques using the current 3-D data volumes. Further, the 3-D S-wave data was collected using a single S-wave source direction which limits the amount of information which can be extracted from the S-wave seismic data.

Conclusions

The P-wave and S-wave seismic data collected over the eastern edge of Lambert field successfully mapped compartmentalization within the Terry Sandstone reservoir. Compartmentalization is controlled by both lithologic and structural components of the reservoir. The structural interpretation would have been possible utilizing the P-wave seismic data alone. The S-wave data allowed additional confidence in the interpretation.

A number of seismic data acquisition and processing techniques have advanced since early 1982 when this data was acquired and processed by Amoco Production Company. Modern acquisition geometries would improve the offset, azimuth, and fold distribution of the seismic data. Detailed reprocessing of the seismic data would allow processing parameters to be fine tuned for the Terry Formation reservoir. Processing techniques used for S-waves have changed significantly since these data were processed. These improvements in acquisition and processing would result in greater resolution within the current zone of interest, resulting in a more accurate and detailed seismic interpretation.

Larger 3-D seismic surveys should be used in the future. The small size of the existing 3-D survey creates many changes in the seismic response due to edge effects. A larger survey would allow greater uniformity of seismic data and more confidence in interpreting subtle changes in the seismic character.

The potential exists in Lambert field to use the P-wave data in conjunction with the S-wave to delineate the reservoir lithology. Bergstrom (1994) showed, using core plug velocity measurements, that cross plots of V_P/V_S versus V_S indicated lithology. Using two orthogonal S-wave source and receiver orientations during the shear wave data acquisition would aid in seismic

anisotropy determination and allow V_P/V_S ratios to be used for lithology determination during the interpretation. Bergstrom (1994) also concluded that S-wave seismic amplitudes would better delineate the sand bodies themselves, allowing the reservoir to be mapped in greater detail. Further, the S-wave data would provide a link between seismic anisotropy and permeability.

Acknowledgments

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Figure 1: North-south oriented compressional (P) wave seismic line extracted from the 3-D seismic survey. Horizons marked are: Terry (900ms), Niobrara (1320ms), and J ss (1470ms).

Figure 2: North-south oriented shear (S) wave seismic line extracted from the 3-D seismic survey. Horizons marked are: Terry (1920ms), Niobrara (2730ms), and J ss (3020ms).

Figure 3: Time structure map on the top of the Terry formation. Blue colors are time highs (dark blue is 880ms) and red colors are time lows (dark red is 930ms).

Figure 4: Time structure map on the top of the J sandstone. Blue colors are time highs (dark blue is 1430ms) and red colors are time lows (dark red is 1490ms).

Figure 5: Time slice extracted from the P-wave seismic volume at 912ms. The red area to the south of the northeast-southwest trending faults is at the Terry reservoir level.

Figure 6: Shear-wave cube display showing the relationship of the faulting to the Terry reservoir. The Terry reservoir appears at approximately 1900ms. The view is looking toward the west.

Appendix C

Petrophysical Analysis

by

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Introduction

The Terry Sandstone studied in the Hambert-Aristocrate area presents several petrophysical difficulties. These challenges are a result of clay conductivity, laminar distribution of clays and sands, and the possible effects of light hydrocarbons. Pay zone recognition is difficult due to conductive clays resulting in low resistivity. The Neutron-Density combination that is typically used to detect gas is not completely effective in the Terry. Thus the Neutron-Density log does not provide support for gas-oil or oil-water fluid contacts. Finally, the clay content of the formation necessitated the use of a shaly sand model to account for the conductive clays. Laminar thin bedded pay sands are difficult to quantify because they tended to be thinner than the vertical resolution of the logging devices.

Approximately 30 wells were studied during the first phase of the project. These wells were studied to gain a regional perspective before focusing on the detailed study area. Overall about 220 logs were digitized and analyzed. Log Analysis Summary Plates, Fig. 1, were generated for each well. These summary plates present the suite of logs for each well on a consistent scale and a summary of the log derived values for net pay, average water saturation, average porosity, hydrocarbon thickness, the source of the shale volume calculation and the methods for calculating water saturation and porosity. Table 2A and 2B present examples of the petrophysical results before and after integration. Table 1A and 1B provide a summary of the important assumptions used in the log analysis before and after integration respectively.

The detailed petrophysics for the Vern Marshall were combined with core information and the minipermeameter analysis to develop a general permeability correlation. The following sections discuss how the petrophysical challenges were addressed. The permeability correlation and specific examples providing support for the sealing fault and the geophysical interpretation are also presented. Core data was sparse but carefully examined and integrated into our analysis. Physical core was invaluable for the petrophysical effort, and was also used by the Geophysical and Geological Teams.

Clay Mineralogy

Information relating to clays is particularly scarce in the Terry formation. Several pieces of information from the initial digital well log processing, well files and literature references regarding core measurements indicate that illite and smectite are the predominant clays. From the Neutron Density Crossplot, it appears that illite alone is the major clay constituent in the Terry formation (Figs. 2 & 2a). Figures 2b, 2c, 2d, and 2e show clay mineralogy from the NGS-LDT (Schlumberger,) combination and generally agree with other results to date.

A Clay Mineralogy Report (X-Ray Diffraction) on the Reeve 41-15 (NE/NE Sec. 15, T. 4 N., R. 65 W.) indicates that illite is the dominant clay with some smectite and traces of kaolinite. Finally, Kolodzie (1980) studied a nearby Terry producing field and from

their X-Ray Diffraction work also found illite to be the dominant clay mineral found in the pores of the Terry. They also found montmorillonite but in lesser amounts.

In summary, the log analysis supports dominantly illite with some montmorillonite-smectite and possible traces of kaolinite as the clay mineralogy. Montmorillonite-Smectite clays are highly effective and swell when in contact with fresh water. Other clays swell to a much lesser degree.

Shaly Sand Saturation Model

Due to the lack of detailed Cation Exchange Capacity (CEC) information, the Waxman-Smiths model becomes difficult to use. However, Juhasz (1981) has shown that for consistent types of clays and formation waters, the Waxman-Smiths equations can be used without CEC information by normalizing the Q_v parameter. The Juhasz modified Waxman-Smiths equations is:

$$Q_{vn} = \frac{V_{sh} \phi_{Dsh}}{\phi_T}$$

$$S_{wT} = \left[\frac{\phi_T^{-m^*} R_{we}}{R_T} \right]^{\frac{1}{n^*}}$$

$$\text{Where } R_{we} = \frac{R_w \cdot R_{wsh} \cdot S_{wT}}{R_{wsh} (S_{wT} - Q_{vn}) + R_w Q_{vn}}$$

Terminology is summarized at the end of the this appendix.

The solution of the equation is still iterative but very useable when the more typical shale volume indicators such as the SP, Gamma Ray, and Neutron-Density are available.

This model was used to process approximately 30 wells in the Terry to evaluate regional saturations. A composite Pickett plot was made from this data in Figs. 3 & 3a showing a vertical trend indicating formations above the transition zone which should produce water-free hydrocarbons. This observation is consistent with the water production data from wells in the study area.

Table 3 Schlumberger (1991) provides a summary of clay properties required for log analysis.

Clay Distribution

Clay distribution does not affect the modified Waxman-Smits method, however insight into the distribution of clays in the formation may be derived from the method. Thomas & Stieber (1975) combined the normalized Waxman's Q_v with porosity and shale volume plots to help identify shale distributions. Figures 4a, 4b, and 4c are combined plots of 7 wells showing trends in the shale distribution for the Lambert-Aristocrat study area. This method alone did not identify the different shale distributions in the Lambert-Aristocrat study area. However, these plots when coupled with core descriptions can be used to support the assumptions about the shale distribution in wells without a core. Changes in the trend would indicate a change in the distribution of the clays.

Discriminating Pay

Traditional Approach

The traditional approach to identifying pay is to assume porosity, water saturation, and shale content cutoffs. The initial net pay calculations in this study were made using the following cutoffs:

Parameter	Value
Porosity	3%
Water Saturation	55%
Shale Volume Cutoff	40%

Bulk Volume Water

Regional log analysis work has helped to understand the characteristics of the Terry Sandstone and how to interpret this shaly sandstone reservoir. The R_z technique was crucial in the calculations of BVW (bulk volume water). The z denotes a mixed water zone defined as the resistivity of the water in the flushed zone that is a mixture of R_{mf} and R_w . The relative amounts of each are calculated based on work done by Tixier (1949) in the Rocky Mountain area. Since the Terry has very low permeabilities, the invasion process is one of slow diffusion of fresh drilling mud filtrate into the formation. The clays hold formation waters near their surfaces and are diluted somewhat by the mud filtrate, leaving a mixture of waters in the flushed zone.

When using Induction logs, as is the case in the study area, the invasion profile is as follows in a productive hydrocarbon bearing zone (from low to high resistivity) Deep, Medium, and then the Shallow (SFL) tool due to fresh water in the near wellbore area. What this means is that the shallow tools almost always read a higher resistivity than the deep investigation tools in the pay and non-pay zones. The flushed zone quicklook method is not typically used in this borehole/formation environment. Using the correct

flushed zone water resistivity (R_z) a flushed zone can be calculated and pay can be identified. For illustration, Archie's law is applied ignoring shale volume corrections.

True Formation

$$S_w = \sqrt[n]{\frac{a \times R_w}{\phi^m \times R_t}}$$

Flushed Zone

$$S_{xo} = \sqrt[n]{\frac{a \times R_{mf}}{\phi^m \times R_{xo}}}$$

Mixed Water

$$S_z = \sqrt[n]{\frac{a \times R_z}{\phi^m \times R_{xo}}}$$

Common logging convention places R_{mf} as the resistivity of the water in the flushed zone. Because of the invasion processes specific to the Terry, R_z is the true nature of the water that is in the flushed zone. When this is not taken into account, invasion is very subtle to detect.

To calculate the moved hydrocarbons due to invasion, typically BVW is compared to BVXO (bulk volume for the flushed zone). In the case of induction logs this will always indicate that there is pay everywhere due to the nature of the contrast in water resistivities. When the mixing of the fresh mud filtrate with the saline formation water is considered, there will be an indication of flushed hydrocarbons. The mixing scenario is a more realistic model than the flushed zone model since the clays still have a relatively high concentration of formation water that is trapped in their matrix and on their surfaces. The very low permeability of the formation also keeps the flushed zone from truly being flushed of all of the original formation water.

The BVW- R_z processing has also enhanced the ability to see the laminated sands in most wells. The technique does not enhance the vertical resolution of the logging tools, but does enhance the ability to see invasion. In early work, cutoffs such as porosity, water saturation and shale volume were used to define pay. Using the difference between BVW and BVXO as a pay indicator is a more realistic way to discriminate pay. The Amoco UPRR 36 Pan Am C #1 well is a good example of the pay indicator improvement (See Figs. 5 and 6). The following is a comparison of the derived log parameters using the BVW-BVXO method and values for S_w , ϕ , and V_{sh} used to mimic the BVW-BVXO method.

Parameter	Using Cutoffs for Sw, ϕ , and Vsh to mimic BVO-BVX	Using BVW-BVXO
Net h (ft)	56.00	46.50
ϕ avg. (%)	16.73	17.05
Sw avg. (%)	44.50	49.97
Hydrocarbon Feet	5.20	3.97

From Fig. 5 you can see pay indicated from 4462-4467 that is probably non-pay shale. Pay is indicated by tics on the right hand side of the log. Almost the entire interval from 4490 - 4546 is marked as pay even when we know that the sands are typically laminated. A short interval of the better pay is not recognized by the early technique from 4529-4536.

Figure 6 shows a much more realistic indication of pay that is consistent with log signatures, our current geological model, and is much simpler to apply. **Tuning cutoffs to mimic the BVW-Rz technique may work on one well, but may not systematically apply to all wells. The BVW-Rz technique is a better universal pay discriminator. However, in this study, cutoff values for Sw, porosity, and shale volume were used to estimate net pay. This was done because of the inconsistency in the quality of the hard copies that the digitizing was based. Digitized data should be obtained directly from the service company when the logs are run.**

In summary, the BVW-BVXO technique can help discriminate pay and correlates very well to the minipermeameter measurements. Although we have found the method to be useful in the discrimination of pay zones, the amount of the flushing and how it relates to permeability may not be a good consistent inference tool. This is because the quality of the digital data can make a big difference in the results of the inferred permeability. A more thorough investigation may enhance this technique, however, we gained the valuable integration and knowledge regarding pore volume from the comparison of several wells and used these results to adjust traditional pay cutoffs accordingly.

Revised Cutoffs

The integration with production data shows that the traditional type of cutoffs (Porosity, Water Saturation, and Shale Volume) were pessimistic when compared to ultimate recoveries and reasonable recovery efficiencies. The values first used in the analysis of the logs were summarized earlier. Later in the project when comparing log and core data it was found that the moved hydrocarbons related to the minipermeameter data as previously reported. The moved hydrocarbon or BVW-BVXO was used to help discriminate pay zones in the Vern Marshall well and showed that there is much more pay than the traditional cutoffs would indicate.

When using the traditional cutoffs the well would drain its own spacing plus that of several other nearby producers. Given that there are no discernible natural fractures near

the well, a) the volumetric calculations must be pessimistic, or b) the logs are miscalibrated, or c) the production data is a combination of several formations/wells.

It is most likely that the volumetrics are pessimistic although there are production reports that are for a 'lease' of many wells, and density logs can be miscalibrated. Upon inspection of the production data it appears that the production is for the Terry sandstone and for the Vern Marshall only. The hole conditions were good for logging and there are no apparent indications of a miscalibrated log.

When the BVW-BVXO technique is used for discriminating pay there is an increase in pay. The result is an integrated volumetric-production picture that is much more reasonable. Pay cutoffs that roughly coincide with the BVW-BVXO technique are:

Porosity Cutoff	8%
Water Saturation Cutoff	65%
Shale Volume Cutoff	45%

Water saturation is the most sensitive parameter as shown in the following analysis:

Technique	Phi	Sw	Vsh	HC-ft	Net Pay
RUN1	8%	50%	40%	1.96	29.5
RUN2	8%	55%	45%	2.50	40.5
RUN3	8%	60%	45%	2.80	47.5
RUN4	8%	65%	45%	2.89	50.0
BVW-BVO				2.88	57.0

Permeability Correlation

The analysis of the Vern Marshall core-log-minipermeameter data indicates that the shale below the Terry is significantly different from the shale in and above the Terry and causes problems when comparing the data. When this data is removed, several parameters compare well with the permeability from the minipermeameter. The BVW parameter is most highly correlated. Figure 7 shows the permeability-BVW correlation using the raw minipermeameter data. Figure 8 shows the minipermeameter data filtered to account for sample size and as suspected has a better correlation coefficient. This relationship will be a useful beginning point in the simulation as well as the for the reserve estimation of individual wells. The derived relationship between minipermeameter permeability and Bulk Volume Water is shown in Fig. 8.

The permeability index as calculated from the above empirical relationship is plotted on the Log Analysis Summary Plates. This derived correlation allows the empirical calculation of a permeability index for wells without a core. Geological and geophysical information for Sec. 17 and 20 agree with the derived k permeability values. The k*h map

(Fig. 9) demonstrates this agreement in terms of the gradually decreasing reservoir quality to the northeast. This trend in reservoir quality is supported by the geophysical interpretation Fig. 10 (Appendix B). Finally, the permeability index calculated from the correlation is in units of millidarcies of air permeability at laboratory conditions. The permeability index needs to be adjusted for overburden conditions and fluid saturations to arrive at an effective permeability prior to use in the simulation model.

Support for Sealing Faults

The HSR Salisbury 6-29 (API 15407) has a very low porosity and when compared to the 3-D seismic and the geological interpretation it appears that this well is in a down-dropped fault block, Fig. 11. It is postulated that this block has experienced diagenetic cementing which has almost completely diminished primary porosity. This interpretation offers support that the faults are sealing and compartmentalizing the reservoir.

Porosity, Net Pay, and Saturation Distributions

Distributions for porosity, water saturation, net sand thickness, permeability-thickness product, temperature gradient, and hydrocarbon thickness were derived from the log analysis data. These distributions are presented as Figs. 12-17.

Conclusions

1. Initial volumetric estimates using traditional cutoff values for porosity, water saturation, and shale volume understate reserves. The BVW calculations and the R_z method to account for the true resistivity in the flushed zone provide a better discriminator for pay. Initial volumetric estimates increased by a factor of 1.50 using revised cutoff values for porosity, water saturation, and shale volume that closely model the BVW calculations.
2. The Juhasz modified Waxman-Smiths model as tuned in Table 1B is representative for the shaly Terry formation.
3. The Neutron Density tool combination does not indicate gas due to the high clay content. The Neutron-Sonic log overlay may be more useful to identify gas in this type of formation according to preliminary investigations.
4. Clay mineralogy is dominantly illite with some montmorillonite-smectite and possibly traces of kaolinite.
5. Empirical plots alone did not identify the different shale distributions. These plots when coupled with core descriptions can be used to support the assumptions about the shale distributions in wells without a core. Change in the trend would indicate a change in the distribution of the clays.

6. A correlation for estimating the permeability based on Log-Core-Minipermeameter data was derived. This correlation permits estimates to be made for all wells and is a starting point for simulation permeability grids.
7. The low porosity in the HSR Salisbury 6-29 (API 15407) when coupled with the 3-D seismic and the geological interpretation (that places the well near a fault) offers support that the faults are sealing and compartmentalizing the reservoir.

Terminology

- R_{mf} resistivity of the mud filtrate
- m^{λ} clay corrected cementation factor, W-S model
- n^{λ} clay corrected saturation exponent, W-S model
- Q_{vn} normalised Q_v , Q_v/Q_{vsh}
- R_t resistivity of hydrocarbon bearing formation (ohm.m), $R_t = 1/C_t$
- R_w (formation) water resistivity (ohm.m), $R_w = 1/C_w$
- R_{wsh} equivalent bulk water resistivity of shale at $S_{wt} = 1.0$;
used for simplicity to denote $1/C_{wash} = 1/C_{wsh}$ at $S_{wT} = 1.0$
- R_{wc} equivalent bulk water resistivity of shaly formation, $R_{wc} = 1/C_{wc}$
- S_{wT} total water saturation, volume fraction of ϕ_T
- ϕ_T total porosity, including 'clay-bound' water) as defined in section 10
- ϕ_{Tsh} total porosity of shale, from density log (ϕ_{Dsh})

References

Juhasz, I. (1981,). Normalised Q_v - The Key to Shaly Sand Evaluation Using the Waxman-Smits Equation in the absence of Core Data. Paper presented at the SPWLA 22nd Annual Logging Symposium.

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CSM/DOE - TERRY
Preliminary Work Product
Contract No. DE-AC22-93BC14891

Task 1.1.2

OPERATOR : AMCO PRODUCTION COMPANY
WELL : UPRR 36 PAN AM C #2
COUNTY : WELD
STATE : COLORADO
DEPTH : 4280.0
Date Logged : 12 NOV 1984
API Number : 06131211
RMB : 4882.0
PROCESS DATA: 08/02/1984 / 10.30

109 99068UFFS!
105E-7-3W
QZCZ PERM ()
CHALE 465 m
221 051880

12174721
18-09
45.30
5.34
47.26
Hinton near
W-1087

Foot
Trail
Trail
Hinton near

Fig. 1 Example log analysis summary plate.

CSM/DOE - SUSSEX
Preliminary Work Product

*****COMBINED FLOT*****
WELLS : 1 JULY 7 WELLS
COUNTY : HELL
STATE : COLORADO
API Numbers : 12653, 97233
15330, 12112
12648, 11684
17902
DATE/TIME : 07/01/1994 / 09:19

Study Area

Montmorillonite
clay point

Illite
clay point

Fig. 2 Neutron - density cross plot with clay points.

Fig. 2a Neutron - density cross plot with clay points.

Mineral Identification of Clays

CSM/DOE - SUSSEX
Preliminary Work Product

OPERATOR : VESSELS OIL AND GAS CORP
WELL : DINNER #14-B1
COUNTY : WELD
STATE : COLORADO
DEPT : 4348.0 - 4540.0
WIT : -NA-
API Number : 0612317813
RKB : 4733.0
DATE/TIME : 07/07/1994 / 08:48

Study Area

R66W	R65W	T4N	T3N
x

Fig. 2b Clay identification from photoelectric Thorium/Potassium ratio.

Mineral Identification of Clays

CSM/DOE - SUSSEX
Preliminary Work Product

C-17

Fig. 2c Clay identification from photoelectric Thorium/Potassium ratio.

OPERATOR	: VESSELS OIL AND GAS COMP
WELL	: DINNER #14-B1
COUNTY	: WELD
STATE	: COLORADO
DEPTHS	: 4340.0 - 4540.0
UWI	: -NA-
API Number	: 0612317813
RKB	: 4733.0
DATE/TIME	: 07/07/1994 / 08:48

Study Area

R66W	R65W	
x		T4N
		T3N

Mineral Identification of Clays

CSM/DOE – SUSSEX
Preliminary Work Product

OPERATOR	: VESSEL OIL AND GAS COMPA
WELL	: DINNER E. UNIT #1
COUNTY	: WELD
STATE	: COLORADO
DEPTHS	: 4350.0 - 4540.0
UNI	: -NA-
API Number	: 0512317902
RKB	: 4730.0
DATE/TIME	: 07/06/1994 / 16:19

Study Area

R66W	R65W	
x		T4N
		T3N

Fig. 2d Clay identification from photoelectric Thorium/Potassium ratio.

Mineral Identification of Clays

CSM/DOE — SUSSEX
Preliminary Work Product

OPERATOR	: VESSEL OIL AND GAS CORP
WELL	: DINNER E. UNIT #1
COUNTY	: WELD
STATE	: COLORADO
DEPTHS	: 4360.0 - 4540.0
UWI	: -NA-
API Number	: 0612317902
RKB	: 4730.0
DATE/TIME	: 07/06/1994 / 16:19

Study Area

R66W	R65W	
x		T4N
		T3N

Fig. 2e Clay identification from photoelectric Thorium/Potassium ratio.

Fig. 3 Pickett plot for 30 Terry sandstone wells.

UNRECORDED PLOT: 28 WELLS
WELLS : 1 JULY
COUNTY : FIELD
STATE : COLORADO
API Numbers Listed on Report

DATE/TIME : 07/01/1994 / 09:21

Study Area

	T4N	T3N
R66W	10 points	1 point
R65W	0 points	0 points

Pickett Plot

Fig. 3a Pickett plot.

Fig. 4a Shale distribution plot (Juhasz, '81, Fig. 12).

Fig. 4b Shale distribution plot (Juhasz, '81, Fig. 13).

Fig. 4c Shale distribution plot (Juhasz, '81, Fig. 14).

CSM/DOE -- TERRY
Preliminary Work Product
Contract No. DE-AC22-93BC14891

Task 1.1.2

OPERATOR	1	AMMO PRODUCTION COMPANY
WELL	1	UPR 36 PAN AN C #1
COUNTRY	1	WELD
STATE	1	COLORADO
DEPT	1	4650.0 - 4806.0
Date Logged	1	19 NOV 1984
API Number	1	061312174
NS	1	4807.0
PROCESS DATE	1	01/01/1990
		13.30

12177731 feet
45.38 feet
47.86 feet
Minimum wheel
to ground
10.08 feet

Fig. 5 UPRR 36, Net pay using values of S_w , Φ , and V_{sh} to mimic BVO - BVXO method.

SPOT LOCATION
4N65W 33 SW SW

CSM/DOE -- TERRY
Preliminary Work Product
Contract No. DE-AC22-93BC14891

Task 1.1.2
OPERATOR : AMMOB PRODUCTION COMPANY
WELL : UPPER 36 PAN AM C #1
COUNTY : WELD
STATE : COLORADO
DEPT : 4450.0 - 4890.0
DATE LOGGED : 19 NOV 1994
ASL NUMBER : 0512312174
PROCESS DATE : 09/01/1998 / 13148

LOG FOOTAGE: 12174.78 feet
LOG DATE: 11-18-94
LOG TIME: 4:23 PM
LOG BY: PERM (S)
LOG SITE: 35.15 mft
LOG TYPE: MINIMUM
LOG FILE: 4450
LOG PATH: 4450

Fig. 6 UPRR 36, Net pay using BVO - BVXO method.

LOG-CORE Relationships
Vern Marshall #1

Fig. 7 Correlation of bulk volume water versus un-filtered minipermeameter permeability (md) for Vern Marshall #1.

LOG-CORE Relationships Vern Marshall #1

Fig. 8 Correlation of bulk volume water versus filtered minipermeameter permeability (md) for Vern Marshall #1.

Possible Northwest-Southeast Fault?

Major Northeast-Southwest Fault

Fig. 10 Amplitude reflection on top of Terry showing trend similar to kh trend and stratigraphic interpretation.

Fig. 11 Well 15407 where diagenetic cementing near fault has reduced primary porosity.

Descriptive Statistics for HCFT

DATA PTS = 181
 AVERAGE = 1.458475
 AVE DEV = 1.088671
 STD DEV = 1.360134
 VARIANCE = 1.849965
 SKEWNESS = 1.178234
 CURTOSIS = 1.896953

Fig. 12 Hydrocarbon thickness distribution for Terry sandstone in Hambert-Aristocrat study area.

Descriptive Statistics for KH
 DATA PTS = 181
 AVERAGE = 100.376500
 AVE DEV = 82.125650
 STD DEV = 134.671700
 VARIANCE = 18136.470000
 SKEWNESS = 4.344039
 CURTOSIS = 27.989300

Fig. 13 Laboratory condition permeability distribution. A correction is necessary to relate to subsurface conditions.

Descriptive Statistics for NET
 DATA PTS = 181
 AVERAGE = 23.852780
 AVE DEV = 17.214850
 STD DEV = 20.579230
 VARIANCE = 423.504700
 SKEWNESS = 6.751226E-01
 CURTOSIS = -3.751574E-01

Fig. 14 Net sand thickness distribution for Terry Sandstone in Hambert-Aristocrat study area.

Descriptive Statistics for SW
 DATA PTS = 162
 AVERAGE = 4.159864E-01
 AVE DEV = 6.720088E-02
 STD DEV = 8.398928E-02
 VARIANCE = 7.054200E-03
 SKEWNESS = -1.291228E-01
 CURTOSIS = 7.206098E-02

Fig. 15 Average water saturation distribution for Terry Sandstone in Hambert-Aristocrat study area.

Descriptive Statistics for PHI

DATA PTS = 162
 AVERAGE = 1.049626E-01
 AVE DEV = 1.231048E-02
 STD DEV = 2.851307E-02
 VARIANCE = 8.129952E-04
 SKEWNESS = 8.374983
 CURTOSIS = 87.409330

Fig. 16 Average porosity distribution for Terry Sandstone in Hambert-Aristocrat study area.

Descriptive Statistics for TG
DATA PTS = 180
AVERAGE = 1.804576
AVE DEV = 1.964829E-01
STD DEV = 2.881239E-01
VARIANCE = 8.301538E-02
SKEWNESS = 1.118708
CURTOSIS = 7.908454

Fig. 17 The temperature gradient distribution from log header information. Corrections for time since circulation have been made. Some of the wells in the above data set were drilled to deeper horizons and the temperature gradient may be different for this set of wells.

TABLE 1A

Assumptions for Petrophysical Analysis Before Integration of Production and Permeability Data

LITHOLOGY - POROSITY PARAMETERS

Porosity Method 1=Density,2=Sonic,3=Neutron, 4=Neutron-Density Crossplot, 5=COMPLEX1 (SS,LS,DL,ANH), 6=COMPLEX2(LS,DL,ANH,GYP),7=SHALY(Method3)	Shaly
Matrix Density (g/cc)	2.65
Fluid Density (g/cc)	1.00
Compressional Travel Time of the Matrix (us/ft)	55.5
Compressional Travel Time of the Fluid (us/ft)	189.0
Preferred Lithology of Neutron Log 0-Lime 1-Sand 2-Dolo	1
Neutron Porosity of Fluid in LSPU	1.0
Volume cross section of Water (b/cc) Freshwater=0.398 Saltwater=1.360	0.398
Tolerance of caliper for Density Tool in/0.5ft	0.1
Rz Lithology Parameter 0.10 Tight 0.075 Avg 0.05 Coarse 0.035 Vuggy	.10

GENERAL WATER SATURATION PARAMETERS

Saturation Method; Archie = 1 Waxman = 2, Simandoux = 3, ALL = 4	Waxman
Resistivity of Formation Brine	0.0650
Temperature of Formation Brine	145.0
Sxo = Sw^(1/X)	5.0
Annual Mean Surface Temperature	60 °F

ARCHIE PARAMETERS

(a) ARCHIES	1.0000
(m) Archies Tortuosity Factor	2.0000
(n) Archies Saturation Exponent	2.0000

SIMANDOUX PARAMETERS

Shale Resistivity for Simandoux(Ohm-m)	3.0
--	-----

JUHASZ-WAXMAN PARAMETERS

Qv for Waxman & Smits	8.0
Waxman's n* exponent	2.2100
Waxman's m* exponent	2.2000
Waxman's Rwsh from the pickett plot	0.0070

SHALE PARAMETERS

Vclay Method 1=SP,2=GR,3=ND,4=Min	GR
Clean Gamma Ray(Sand)	60.0
Matrix Gamma Ray(Shale)	150.0
Density Porosity of Shale Point	0.045
Neutron Porosity of Shale Point	0.160
Standardized RMF for SP analysis	3.0
Standardized RMF Temp. for SP analysis	150.0
Clean Spontaneous Potential Deflection	-15.0

PAY INDICATOR PARAMETERS

Porosity Cutoff	0.03
Water Saturation Cutoff	0.55
Shale Volume Cutoff	0.40

TABLE 1B

Assumptions for Petrophysical Analysis After Integration of Production and Permeability Data

LITHOLOGY - POROSITY PARAMETERS

Porosity Method 1=Density,2=Sonic,3=Neutron, 4=Neutron-Density Crossplot, 5=COMPLEX1(SS,LS,DL,ANH, 6=COMPLEX2 (LS,DL,ANH,GYP, 7=SHALY(Method3)	Shaly
Matrix Density (g/cc)	2.65
Fluid Density (g/cc)	1.00
Compressional Travel Time of the Matrix (us/ft)	55.5
Compressional Travel Time of the Fluid (us/ft)	189.0
Preferred Lithology of Neutron Log	
0-Lime 1-Sand 2-Dolo	1
Neutron Porosity of Fluid in LSPU	1.0
Volume cross section of Water (b/cc)	
Freshwater=0.398 Saltwater=1.360	0.398
Tolerance of caliper for Density Tool in/0.5ft	0.1
Rz Lithology Parameter	
0.10 Tight 0.075 Avg 0.05 Coarse 0.035 Vuggy	0.10

GENERAL WATER SATURATION PARAMETERS

Saturation Method; Archie = 1 Waxman = 2, Simandoux = 3, ALL = 4	Waxman
Resistivity of Formation Brine	0.0650
Temperature of Formation Brine	145.0
Sxo = Sw ^(1/X)	5.0
Annual Mean Surface Temperature	60 °F

ARCHIE PARAMETERS

(a) ARCHIES	1.0000
(m) Archies Tortuosity Factor	2.1000
(n) Archies Saturation Exponent	2.1000

SIMANDOUX PARAMETERS

Shale Resistivity for Simandoux(Ohm-m)	3.0
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JUHASZ-WAXMAN PARAMETERS

Qv for Waxman & Smits	8.0
Waxman's n* exponent	2.1000
Waxman's m* exponent	2.1000
Waxman's Rwsh from the pickett plot	0.0063

SHALE PARAMETERS

Vclay Method 1=SP,2=GR,3=ND,4=Min	GR
Clean Gamma Ray(Sand)	50.0
Matrix Gamma Ray(Shale)	150.0
Density Porosity of Shale Point	0.075
Neutron Porosity of Shale Point	0.300
Standardized RMF for SP analysis	3.0
Standardized RMF Temp. for SP analysis	150.0
Clean Spontaneous Potential Deflection	-15.0

PAY INDICATOR PARAMETERS

Porosity Cutoff	0.08
Water Saturation Cutoff	0.60
Shale Volume Cutoff	0.45

TABLE 2A

Sample of Petrophysical Results Before Integration of Production and Permeability Data

<u>API</u>	<u>XLOC</u>	<u>YLOC</u>	<u>EKB</u>	<u>WELL</u>	<u>FILE</u>	<u>TOP</u>	<u>BOTTOM</u>	<u>GROSS</u>	<u>NET</u>	<u>PHIAVG</u>	<u>SWAVG</u>	<u>kh</u>	<u>hcft</u>
7265	22695	16025	4987	J. J. Wardell No. 1	07265F20	4500	4700	200	0	0	1	0	0
7470	38715	23934	4768	Donald J. Moser No. 1	7470820	4300	4500	200	0	0	1	0	0
7533	29400	29300	4585	UPRR #21 PRM American D"	7533320	4400	4600	200	0	0	1	0	0
7545	22357	37356	4731	Kinsman No.1	07545R20	4300	4500	200	11	0.129354	0.512317	43.6	0.6939212
8267	26718	21315	4941	MEL SMOOKLER #1	8267620	4500	4700	200	0	0	1	0	0
8397	24067	31902	4784	C.J. Schmidt No. 1	08397S20	4400	4600	200	14	0.121893	0.505177	49.7	0.8444164
8414	38397	21625	4762	Aristocrat Angus Ranches	8414820	4250	4450	200	2	0.275339	0.390253	58.7	0.3357743
8658	21697	35576	4745	Warren McMillen #1	08658S20	4300	4500	200	0	0	1	0	0
8670	29474	25271	4906	#1 Musick-McClintock	8670620	4450	4650	200	0	0	1	0	0
8867	21695	40839	4706	Jack C. Noel #1	08867R20	4250	4450	200	9.5	0.128621	0.508189	37.6	0.6009436

TABLE 2B

Sample of Petrophysical Results After Integration of Production and Permeability Data

<u>API</u>	<u>XLOC</u>	<u>YLOC</u>	<u>EKB</u>	<u>WELL</u>	<u>FILE</u>	<u>TOP</u>	<u>BOTTOM</u>	<u>GROSS</u>	<u>NET</u>	<u>PHI AVG</u>	<u>SWAVG</u>	<u>kh</u>	<u>hcft</u>
7265	22695	16025	4987	J. J. Wardell No. 1	07265F20	4500	4700	200	0	0.63387	0.0153	0	0
7470	38715	23934	4768	Donald J. Moser No. 1	7470820	4300	4500	200	23.5	0.39145	0.04291	54.93467	1.159111
7533	29400	29300	4585	UPRR #21 PRM American D"	7533320	4400	4600	200	0	1	0	0	0
7545	22357	37356	4731	Kinsman No.1	07545R20	4300	4500	200	45.5	0.45658	0.05191	201.0127	3.044341
8267	26718	21315	4941	MEL SMOOKLER #1	8267620	4500	4700	200	3	0.65806	0.02452	9.03373	0.17287
8397	24067	31902	4784	C.J. Schmidt No. 1	08397S20	4400	4600	200	53.5	0.40199	0.04798	227.2609	3.481318
8414	38397	21625	4762	Aristocrat Angus Ranches	8414820	4250	4450	200	26.5	0.38411	0.0418	59.02946	1.218603
8658	21697	35576	4745	Warren McMillen #1	08658S20	4300	4500	200	21	0.27184	0.07334	66.28997	1.06697
8670	29474	25271	4906	#1 Musick-McClintock	8670620	4450	4650	200	45.5	0.3231	0.04724	113.0609	2.142492
8867	21695	40839	4706	Jack C. Noel #1	08867R20	4250	4450	200	53	0.39511	0.06364	202.945	3.292846

TABLE 3

Log Interpretation Chartbook
(Schlumberger)

Name	Formula	ρ_{LOG} g/cc	ϕ_{SNP} p.u.	ϕ_{CNL} p.u.	t_c $\mu\text{s/ft}$	t_s $\mu\text{s/ft}$	P_o barn/elect	U barn/cc	ϵ farads/m	t_p nsec/m	GR API units	Σ c.u.
CLAYS												
Kaolinite	$\text{Al}_2\text{Si}_4\text{O}_{10}(\text{OH})_2$	2.41	34.	37.			1.83	4.44	~5.8	~8.0	80-130	14.12
Chlorite	$(\text{Mg,Fe,Al})_8(\text{Si,Al})_4\text{O}_{10}(\text{OH})_2$	2.76	37.	52.			6.30	17.38	~5.8	~8.0	180-250	24.87
Illite	$\text{K}_{1-1.5}\text{Al}_4(\text{Si}_{7-8.5}\text{Al}_{1-1.5})\text{O}_{20}(\text{OH})_4$	2.52	20.	30.			3.45	8.73	~5.8	~8.0	250-300	17.58
Montmorillonite	$(\text{Ca,Na})_7(\text{Al,Mg,Fe})_4(\text{Si,Al})_8\text{O}_{20}(\text{OH})_4(\text{H}_2\text{O})_n$	2.12	40.	44.			2.04	4.04	~5.8	~8.0	150-200	14.12

APPENDIX D

Experimental Data Report

by

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EXECUTIVE SUMMARY

The focus of this report is to present the final results of the experimental rock property measurements and to discuss how the data will be used in the integrated study. The rock properties and flow characteristics were measured for the Terry formation in the Hambert area. The measured rock properties were coupled with descriptive interpretations of core sections and subsequently linked with log derived values to develop a correlation for permeability estimates. This integration of data permits estimates of permeability on a field wide basis. Relative permeability, rock compressibility, shear and compressional velocities, Poisson's ratio, and Young's modulus were also measured.

Reservoir core samples of the Machi Ross #1 (Sec. 4, T. 32 N., R. 65 W.), Vern Marshall #1 (NW SW Sec. 32, T. 4 N., R. 65 W.), and Eckhardt #1 (Sec. 15, T. 4 N., R. 66 W.) wells were available and are located in a south-east to north-west trend in the Hambert Field located in the Denver Basin of Colorado (Fig. 1). The wells in the Hambert Field produce oil and gas from the Cretaceous Terry sandstone (also referred as Terry sandstone). Reservoir core samples for these wells were first described geologically by Dr. Roger Slatt, Geology Department of the Colorado School of Mines. These sandstones are thought to have been deposited as sands reworked into offshore ridge complexes during marine transgression. Six facies of different characteristics were identified and classified.

A permeability-depth profile for each core was obtained with the Pressure Decay Profile Permeameter®. Results from the three cores showed a low permeability formation, in the range of 0.015 to 9 md, with variations of permeability related to the facies control (Figs. 2 to 4). Permeability-depth profile measurements of the whole cores showed a good correlation to the facies distribution described by Roger Slatt (Fig. 5 and Appendix A) and to the log calculated values. Production comes from the four facies shown in Fig. 2. The Vern Marshall #1 produces gas from facies 1 and 2 and oil from facies 3 and 4.

Core plugs were taken from the Vern Marshall #1 for further analysis. A multidisciplinary team of geologists, petroleum engineers, and geophysicists selected 17 horizontal and 4 vertical core plugs to constitute a representative set for the well. The core plugs (1 in. in diameter and 3 in. in length), from three productive facies, were cut based on the permeability profile results and variations in the depositional sequences.

Porosity and permeability as a function of the net confining stress were determined from the vertical and horizontal core plugs. Permeability and porosity measurements were performed using the CMS-300 equipment under confining stress conditions of 500, 1000, 2000, 3000, 4000, and 4500 psig. The porosity was found to be in the range of 12% to 16% under ambient conditions, and under the maximum applied confining stress of 4500 psig the porosity was reduced on the order of 1% porosity unit (Figs. 6 to 8). The horizontal permeability was found to be in the order of 0.05 md to 1.8 md under ambient conditions and under the maximum applied confining stress of 4500 psig these values were reduced by 40% (Figs. 9 to 12). The vertical permeability measured in four core plugs (adjacent to the horizontal plugs, see Table 1) showed values in the range of 0.01 to 0.2 md. It was observed, under the maximum confining stress applied of 4500 psig, that these values were reduced 75% to 95%. The vertical to horizontal permeability ratios under ambient conditions varied from 0.11 to 0.15 md.

The vertical to horizontal permeability ratios under the maximum confining stress conditions of 4500 psig resulted in lower values, ranging from 0.017 to 0.063 md (Table 1).

Compressional (P) and shear (S) wave-propagation velocities were measured in the horizontal and vertical core plugs under effective stress of 500, 1000, 2000, 3000, 4000, and 4500 psig. These measurements were made under gas (dry) and liquid saturated conditions (Figs. 13 and 14). For the dry samples, no correlation between the seismic velocities and lithology was found. For the saturated measurements, a V_p/V_s ratio of approximately 1.7 indicates a "cleaner" sandstone (higher reservoir quality) and a ratio of 1.8 indicates a "shalier" sandstone (lower reservoir quality) (Figs. 15 and 16). Samples were grouped as "good" reservoir quality (sample 5, 6, 14 and 17) and "poor" reservoir quality rock (sample 16, 19 and 20). When saturated, the good reservoir quality rocks (high porosity and permeability values) have higher V_s and lower V_p/V_s ratio than the poorer reservoir quality rocks (Figs. 17 to 19). The elastic rock properties (shear modulus, Young's modulus, bulk compressibility and Poisson's ratio) were determined for the selected core plugs.

Description of the whole core and clay content determinations were complimented with petrographic (epoxy-impregnation thin section analysis) and scanning electron microscope analysis on the Vern Marshall #1 (NW SW Sec. 32, T. 4 N., R. 65 W.), Moser #1 (SE NW Sec. 34, T. 4 N., R. 65 W.), Kinsman #1 (SE SW Sec. 18, T. 4 N., R. 65 W.), Moser #1 (SE NW Sec. 34, T. 4 N., R. 65 W.), and Prima Oil Burke 24-3S (SE SE Sec. 24, T. 4 N., R. 65 W). The sandstones examined from all four wells are generally fine-grained, predominantly feldspathic, with variable amounts of carbonate cement mainly calcite. Laminae with almost no carbonate or clay often exhibit extensive quartz cementation. Stylolites are common in the Terry Sandstone in the study area. Clay laminae exhibit incipient stylolites that can inhibit vertical movement of reservoir fluids.

The stylolites, however, are typically discontinuous over long lateral distances. Diagenetic evidence suggests an offshore origin for the sandstones. Petrographic analysis suggests presence of microporosity. Equivalent pore entry radius calculated from mercury-air capillary pressure experiment indicate abundance of less than 2 microns equivalent pore entry radius. Analysis of the scanning electron microscope indicate most pores in the sandstones are on the order of a few microns in diameter (microporosity), and that there are few large (>0.01 mm) pores.

Water-oil displacements were used to determine relative permeabilities and capillary pressures. An experimental apparatus capable of working under lab and under confining stress conditions of up to 5,000 psig and at a reservoir temperature of 140 °F was fabricated. Experiments were performed with 50,000 ppm (NaCl and KCl) brine and kerosene. Berea core plugs were used for preliminary work to test the apparatus and establish a standard reference. For relative permeability experiments, core plug number four from the Vern Marshall #1 was selected based on its homogeneity and relatively high permeability. Measurements were taken on the samples under lab conditions and under in-situ conditions. Under the maximum net applied confining stress of 3500 psig and a reservoir temperature of 140 °F, the relative permeability curves were found to shift slightly to the right while maintaining their characteristic shape (Figs. 20 and 21). The end points exhibited a minor or no shift. Figure 22 shows the simulated relative permeability curves for the imbibition process. Mercury-air capillary pressures were determined and the transformation to water-oil capillary pressure was found to be in

excellent agreement with the experimental water-oil displacement (Fig. 23). A numerical simulation of the experimental water-oil displacement experiments was also performed (Figs. 24 and 25).

The experimental results were integrated with the other project tasks. Experimental porosity and permeability estimates were compared to log derived estimates. A relationship between log derived values and permeability permits estimates of the permeability in other wells that have logs but no core samples. Also, these properties are related to the Vs and the Vs/Vp ratio. The results of the analysis of compressional and shear wave-propagation velocities from core plug samples are used to calibrate the tools used in the geophysical 3-D seismic interpretation. The petrographic analysis suggests carbonate rich and carbonate poor (silica) cement and supports the offshore origin for these sandstones. The rock compressibility, capillary pressures, and relative permeabilities were used as a starting point to the numerical simulation study.

CONCLUSIONS

1. The permeability-depth profiles from the Vern Marshall #1, Machi #1 Ross, and Eckhardt #1 of the Lambert Field reveal low permeability (0.015 to 9 md) and allow identification of the dominant permeability ranges at different depths (Figs. 2, 3, and 4). The dominant permeability ranges at different depths can be related to depositional facies (Fig. 2) and to log interpretation. Permeability estimations from log derived values compared favorably to the permeability profile. A correlation was developed to calculate permeability from log derived values that can be used when core data is lacking.
2. The experimentally determined porosity and permeability data under several confining stress conditions were curve fit to represent how these properties change with increasing stress (Figs. 6 to 12). The empirical relations are given by the equations of the form:

$$\phi = A + Bs + Cs^2$$

and

$$k = A + Bs + Cs^2$$

where:

ϕ	= porosity (decimal)
k	= absolute permeability (md)
s	= confining stress condition (psig)
A, B, C	= regression constants.

The regression constants for the above equations are presented in Table 2 .

3. Horizontal permeability values measured under confining stress of 4500 psig are 40% to 70% smaller than the values of the horizontal permeability under no confining stress. The vertical permeability values measured under confining stress of 4500 psig are 70% to 95% smaller than the values of the vertical permeability under no confining stress (Table 1).
4. The vertical to horizontal permeability ratio (k_v/k_h) under normal lab conditions is in the range of 0.11 to 0.15 and under confining stress of 4500 psig the ratio k_v/k_h is reduced to 0.02 to 0.06 (Table 1).
5. The following relationship between velocity (V) and effective stress (p) was found to fit the data :

$$V = A + B p^{1/3} + C p^{2/3}$$

V = velocity (ft/sec)
 p = confining stress condition (psig)
 A, B, C = regression constants.

The regression constants for the above equations are presented in Tables 3 and 4. Note in this equation that "p" is used in geophysics nomenclature and is equivalent to "s" in petroleum nomenclature used in the second conclusion.

6. For the saturated samples, a V_p/V_s ratio of 1.7 - 1.75 indicates cleaner sandstone (higher reservoir quality) and a ratio of 1.8 - 1.85 indicates a shalier sandstone (lower reservoir quality) (Figs. 15 and 16).
7. The elastic properties, shear modulus ($m = G$), Young's modulus (E), Poisson's ratio (ν) and bulk compressibility (C_b), calculated under 3100 psia and 3600 psia for dry measurements and saturated measurements and for "sand" and "shale" are presented in Table 5.
8. There is no significant change in Young's modulus and the shear modulus for dry to saturated conditions. The bulk compressibility and Poisson's ratio, however, are dependent on whether the samples are dry or saturated.
9. Petrographic and scanning electron microscope analysis indicates generally fine-grained, predominantly feldspathic sandstones with variable amounts of carbonate cement mainly calcite. Laminae with almost no carbonate or clay often exhibit extensive quartz cementation. The presence of stylolites may inhibit vertical movement of reservoir fluids resulting in a tortuous path for reservoir fluid flow.
10. Diagenetic evidence suggests an offshore origin for the sandstones. The high carbonate cement content in these sandstones is thought to indicate the presence of common primary carbonate (sand) grains.

11. Petrographic analysis suggests presence of abundant microporosity. Analysis of the scanning electron microscope indicates most pores in the sandstones are on the order of a few microns in diameter (microporosity), and that there are few large (>0.01 mm) pores.
12. The effect on the relative permeability of increasing the net confining stress, from 200 psig to 3500 psig, and the temperature from 70 °F to 140 °F are favorable to the oil mobility during the oil migration (drainage process) while slightly unfavorable to the oil mobility during the imbibition process (production).
13. The capillary pressure-saturation relationship obtained from the mercury-air experiment and transformed to lab water-oil was found to have excellent agreement with the capillary pressure points obtained from the water-oil experiments (Fig. 23). Relative permeability correlations based on capillary experimental information was tested and compared to the relative permeability of this work.
14. The simulation results were in good agreement with the laboratory observed pressures and production (Figs. 24 and 25). The use of numerical simulation to simulate the experimental displacement experiments is highly recommended to obtain the relative permeability curves because it provides smooth results and also provides information before the breakthrough (missing when using Johnson-Bossler and Naumann method). However, due to the tedious or lengthy process of the trial and error change of the relative permeability curves during the simulation matching process, it is recommended to generate a program to augment the automatic history matching process.
15. No general equation was found to transform the relative permeabilities obtained from measurements under lab conditions to the relative permeabilities under the reservoir conditions.

RECOMMENDATIONS

Following is a summary of the steps developed in the work.

1. Perform the core description, obtain the permeability-depth profiles to understand the permeability distributions and dominant ranges. This information will help in selecting core plugs.
2. Calibrate the logs with the permeability profile and core description to obtain transforms for calculating permeability from log derived values for the wells with logs but no cores.
3. Select core plugs with the participation of an integrated team. This will ensure the samples represent the variety of facies present in the core and are representative for horizontal and vertical permeability and velocity measurements.
4. Measure the permeability and porosity for the core plugs under confining stress and find the equations to transform those parameters from ambient conditions to reservoir conditions.

5. Perform petrophysical measurements of epoxy-impregnated thin sections and scanning electron microscope analysis.
6. Measure the compressional and shear wave-propagation velocities from core plug samples under the same effective stress condition as in c) and calculate the elastic rock properties. Perform experiments with dry cores and cores saturated with brine or other selected fluid. Calibrate the seismic interpretation tools with the results of these measurements.
7. Simulate the displacement experimental process with a numerical simulator, perform sensitivity to the critical variables, and become familiar with the critical steps for the lab process. This will help monitor the critical steps during the experimental process; i.e. breakthrough time and sampling frequency.
8. Perform the displacement experiments and closely monitor the critical steps found during the pre-experiment simulation.
9. Select a core with similar characteristics to the core selected for relative permeability experiments and obtain the capillary pressures by using air-mercury or other experimental techniques.
10. Simulate the experimental process and match against the pressure and production data. Then proceed with the simulation for the next experiment going back to step 6.
11. Once all experiments on the core are finished, use the core to obtain the capillary pressures. Then repeat the simulation to refine the results.
12. Relative permeability correlations based on capillary experimental information should be compared to the experimental/simulated values. The "best" correlation should then be used to find the relative permeability of other facies and other wells.

Fig. 1 Base map - Hambert Field - location of the wells Eckhardt #1, Vern Marshall #1, and Machi 1 Ross.

Fig. 2 Permeability-depth profile Hambert Field - well Vern Marshall #1.

Fig. 3 Permeability-depth profile Hambert Field - well Machi Ross #1.

Fig. 4. Permeability-depth profile Hambert Field - well Eckhardt #1.

Fig. 5 Percent sand-depth profile Hambert Field - well Vern Marshall #1.

Fig. 6 Porosity versus confining stress - well Vern Marshall #1.

Fig. 7 Porosity versus confining stress - well Vern Marshall #1.

Fig. 8 Porosity versus Confining stress - well Vern Marshall #1.

Fig. 9 Permeability versus confining stress - well Vern Marshall #1.

Fig. 10 Permeability versus confining stress - well Vern Marshall #1.

Fig. 11 Permeability versus confining stress - well Vern Marshall #1.

Fig. 12 Permeability versus confining stress - well Vern Marshall #1.

Fig. 13 Velocity versus confining stress.

Fig. 14 Velocity versus confining stress.

Fig. 15 Velocity ratio versus confining stress.

Fig. 16 Velocity ratio versus confining stress.

Fig. 17 Porosity versus velocity.

Air permeability for horizontal samples vs Vp and Vs at 3100 psia effective stress
Air permeability was measured at 4500 psig confining pressure

Fig. 18 Permeability versus velocity.

Fig. 19 Porosity and permeability versus velocity ratio.

Fig. 20 Relative permeability curves first drainage under net confining stresses off 200 psig. T = 70 °F and 3500 psig, T = 140 °F.

Fig. 21 Relative permeability curves experiments 20 and 26, second drainage under net confining stresses of 200 psig, $T = 70^{\circ}\text{F}$ and 3500 psig, $T = 140^{\circ}\text{F}$.

Fig. 22 Relative permeability curves first imbibition core plug VM4.

Fig. 23 Capillary pressure from oil displacing water experiment 18, first drainage, core plug VM4 - net confining stress 200 psig, $T = 70^{\circ}\text{F}$ and air-mercury experiment transformed to water/oil.

Fig. 24 Oil displacing water relative permeability experiment 18, first drainage core plug VM4 - net confining stress 200 psig, $T = 70^{\circ}\text{F}$.

Fig. 25 Oil displacing water relative permeability experiment 18, first drainage core plug VM4 - net confining stress 200 psig, $T = 70^{\circ}\text{F}$.

TABLE 1

**Summary of Permeability and Porosity Measurements
Hambert Field - Well Vern Marshall #1**

Core Plug No	Depth ft	Diameter cm	Length cm	Dry Weigh gr	No Confining Stress				Net Confining Stress 4500 psig				Ratio of Values Stress/Ambient		
					Permab md	Porosity %	Pore Vol cc	kv/kh	Permab md	Porosity %	Pore Vol cc	kv/kh	Permab	Porosity	Pore Vol
1	4672.04	2.51	7.51	86.68	0.121	12.52	4.636		0.021	11.3	4.210		0.174	0.903	0.908
2	4671.67	2.51	7.35	83.66	0.650	13.33	4.835		0.438	12.4	4.477		0.674	0.930	0.926
3	4669.67	2.50	7.51	84.05	1.167	14.13	5.221		1.170	13.2	4.872		1.003	0.934	0.933
4	4668.08	2.51	7.15	79.46	1.840	14.91	5.256		1.370	13.8	4.885		0.745	0.926	0.929
5	4665.96	2.51	7.50	83.61	1.500	14.36	5.329	0.125	0.925	13.5	4.989	0.017	0.617	0.940	0.936
6 Vert	4665.88	2.51	7.52	84.92	0.187	13.76	5.095		0.016	12.8	4.753		0.086	0.930	0.933
7 Vert	4664.92	2.50	7.51	84.44	0.180	14.91	5.525	0.155	0.048	14.2	5.235	0.066	0.267	0.952	0.948
8	4664.67	2.52	7.51	83.86	1.159	15.21	5.759		0.765	14.5	5.423		0.660	0.953	0.942
9	4662.88	2.50	7.54	83.14	1.837	16.16	6.041		1.480	15.4	5.755		0.806	0.953	0.953
10	4661.84	2.50	7.43	82.53	1.276	15.83	5.761		0.816	14.9	5.422		0.639	0.941	0.941
11 Vert	4658.34	2.51	2.45	28.03	0.016	14.85	1.791	0.111	0.001	11.7	1.395	0.028	0.063	0.788	0.779
12	4658.08	2.51	6.97	80.30	0.144	13.05	4.473		0.036	11.8	3.995		0.250	0.904	0.893
13	4656.08	2.49	6.93	77.62	1.020	14.30									
14	4650.92	2.50	7.00	77.76	0.390	16.85	3.435		0.228	15.6	3.171		0.585	0.926	0.923
15	4648.80	2.50	7.53	85.11	0.253	14.50	5.401		0.141	13.7	5.071		0.557	0.945	0.939
16	4645.40	2.50	6.92	79.83	0.129	11.94	4.069		0.014	11.2	3.803		0.109	0.938	0.935
17	4637.90	2.50	7.55	83.77	0.561	15.53	5.754		0.384	14.8	5.478		0.684	0.953	0.952
18	4633.25	2.50	7.59	86.91	0.149	14.31	5.315		0.066	12.8	4.770		0.443	0.894	0.897
19	4627.29	2.50	7.43	85.17	0.495	13.05	4.767	0.111	0.007	12.1	4.410	0.286	0.014	0.927	0.925
20 Vert	4627.12	2.50	6.21	71.75	0.055	11.80	3.553		0.002	11.2	3.420		0.036	0.949	0.963
21	4622.96	2.50	7.52	86.96	0.056	13.38	4.890		0.004	11	4.054		0.071	0.822	0.829

* Max stress 2000 psig

TABLE 2
Parameter Coefficients for Curve Fit

Porosity							
	Core Plug 5	Core Plug 6	Core Plug 9	Core Plug 17	Core Plug 19	Core Plug Berea 1	Core Plug Berea 2
A	14.3612	13.7592	16.1600	15.5334	13.0517	16.808	23.9597
B	-0.000371302	3.96E-08	-0.000280718	-0.000339687	-0.000274664	-0.000295293	-0.000369955
C	-0.0003858	4.02E-08	2.57E-08	3.97E-08	1.34E-08	2.63E-08	3.97E-08

Permeability							
	Core Plug 5	Core Plug 6	Core Plug 9	Core Plug 17	Core Plug 19	Core Plug Berea 1	Core Plug Berea 2
A	1.50047	0.187008	1.83713	0.560179	0.495264	41.3974	549.504
B	-0.000225574	-9.09E-05	-0.000150628	-8.08E-05	-0.000357719	-0.00114484	-0.0113162
C	2.20E-08	1.19E-08	1.60E-08	9.30E-09	6.02E-08	9.29E-08	6.94E-07

Pore Volume							
	Core Plug 5	Core Plug 6	Core Plug 9	Core Plug 17	Core Plug 19	Core Plug Berea 1	Core Plug Berea 2
A	5.32851	5.09452	6.04088	5.75371	4.76658	6.55295	8.38555
B	-0.000153417	-0.000142163	-0.000124292	-0.000113754	-0.000112054	-0.000142253	-0.000144657
C	1.76E-08	1.49E-08	1.37E-08	1.18E-08	7.24E-09	1.57E-08	1.61E-08

TABLE 3

The constants A, B, and C for the best fit equation $V=A+Bp_e^{1/3}+Cp_e^{2/3}$
 where p_e is the effective stress and V is the seismic velocity.

Sample	<u>Dry Vp</u>			<u>Dry Vs</u>		
	A	B	C	A	B	C
1	7977.43	230.379	2.45164	5590.02	53.8949	5.80345
5	7600.98	345.589	-0.883505	5531.51	154.636	1.36246
6	7351.69	151.366	10.5353	4773.26	251.585	-1.83017
14	9185.39	91.548	7.75116	6290.25	53.5639	4.39532
16	9443.85	227.244	-1.37185	5983.98	151.994	-1.21266
17	10117.2	118.464	4.38886	6424.3	87.6907	2.40063
19	10172.4	56.5785	6.71888	7150.22	-28.716	6.22058
20	6603.63	209.355	4.49303	5679.24	107.938	1.59842

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TABLE 4

The constants A, B, and C for the best fit equation $V=A+Bp_e^{1/3}+Cp_e^{2/3}$
 where p_e is the effective stress and V is the seismic velocity.

Sample	<u>Saturated Vp</u>			<u>Saturated Vs</u>		
	A	B	C	A	B	C
1	12377.4	-14.217	5.05396	5662.77	129.735	-0.41666
5	10488.2	262.404	-4.16033	4667.17	280.117	-4.33327
6	10757.9	225.719	-2.3265	4710.43	290.833	-4.77779
14	10885.6	185.194	-1.56252	5977.33	56.2924	3.68567
16	11237.2	125.41	0.04521	5064.07	125.269	0.83528
17	10478.0	340.681	-8.89301	4866.62	300.683	-6.33057
19	12299.2	-46.0168	7.2945	6045.13	27.6383	4.19486
20	10834.2	92.7883	-0.56432	5811.36	-22.593	5.29925

TABLE 5

Rock properties at 3100 psia and 3600 psia effective stress.
Subscript "sand" refers to good reservoir quality rock and subscript "shale"
refers to poor reservoir quality rock. Subscript "ave" refers to the average.

Property	<u>Dry measurements</u>		<u>Saturated measurements</u>	
	$P_e=3100$ psia	$P_e=3600$ psia	$P_e=3100$ psia	$P_e=3600$ psia
μ_{sand} (psi)	$2.000 \cdot 10^6$	$2.064 \cdot 10^6$	$1.973 \cdot 10^6$	$2.023 \cdot 10^6$
μ_{shale} (psi)	$1.948 \cdot 10^6$	$2.007 \cdot 10^6$	$1.770 \cdot 10^6$	$1.819 \cdot 10^6$
μ_{ave} (psi)	$1.980 \cdot 10^6$	$2.043 \cdot 10^6$	$1.872 \cdot 10^6$	$1.921 \cdot 10^6$
E_{sand} (psi)	$4.539 \cdot 10^6$	$4.690 \cdot 10^6$	$4.921 \cdot 10^6$	$5.024 \cdot 10^6$
E_{shale} (psi)	$4.475 \cdot 10^6$	$4.608 \cdot 10^6$	$4.524 \cdot 10^6$	$4.635 \cdot 10^6$
E_{ave} (psi)	$4.507 \cdot 10^6$	$4.649 \cdot 10^6$	$4.723 \cdot 10^6$	$4.829 \cdot 10^6$
v_{sand}	0.1346	0.1359	0.2470	0.2418
v_{shale}	0.1489	0.1477	0.2784	0.2475
v_{ave}	0.1418	0.1418	0.2627	0.2584
Cb_{sand} (1/psi)	$4.831 \cdot 10^{-7}$	$4.672 \cdot 10^{-7}$	$3.085 \cdot 10^{-7}$	$3.085 \cdot 10^{-7}$
Cb_{shale} (1/psi)	$4.712 \cdot 10^{-7}$	$4.600 \cdot 10^{-7}$	$2.900 \cdot 10^{-7}$	$2.855 \cdot 10^{-7}$
Cb_{ave} (1/psi)	$4.771 \cdot 10^{-7}$	$4.636 \cdot 10^{-7}$	$3.011 \cdot 10^{-7}$	$2.999 \cdot 10^{-7}$

TABLE 6

Relative Permeability Experiments with Core Plug VM4
Experiments 18 to 26 on Core Plug Vern Marshall 4

Experiment Number	Initial Sw %	Conf.Stre psig	Temperature °F	Displacement Process	Inj. Rate cc / min	Last Inj. cc / min
Preparation of the Core						
18	100	200	70	Drainage 1	.083	1.66
19	48.48	200	70	Imbibition 1	.083	.083
20	71.58	200	70	Drainage 2	.083	.083
Restoration of the Core						
21	100	3500	70	Drainage 1	.083	1.16
22	51.87	3500	70	Imbibition 1	.083	.083
23	73.83	3500	70	Drainage 2	.083	1.16
Restoration of the Core						
24	100	3500	140	Drainage 1	.083	2
25	46.93	3500	140	Imbibition 1	.083	.083
26	68.89	3500	140	Drainage 2	.083	2

Appendix E

Well Test Analysis, Production Data Analysis, and Well Test Methods

by

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Introduction

Pressure data along with production data are critical for the reservoir engineer. Unfortunately the pressure data is scarce in the Hambert-Aristocrat area. The production reporting also has some limitations. Commingling of production at the lease level coupled along with multiple formation commingling at the well bore are two examples of problems with the data. The following section on Well Test Analysis discusses the interpretation of two well tests in the area. The section on production data analysis presents the application of a production rate type-curve for infinite conductivity vertical fractures (Cox, Kuuskraa & Hansen, 1996). The final section on Well Test Methods presents a summary of well test methods and example applications to demonstrate cost effective ways operators can make the most of available data to characterize the reservoir.

Well Test Analysis

Two pressure build-up tests from the Hambert Field, Weld County, Colorado, have been analyzed. Figure 1 shows the location of the two wells. An estimate of original reservoir pressure and a set of type curves have been used to estimate the drained reservoir volume. Figures 2 and 3 present the logs for the Jack C. Noel #1 and the Warren McMillen #1, the two wells studied.

Bottom-hole pressures were monitored on the Jack C. Noel #1 during a 24-hour draw-down and 1,335-hour build-up. Overall, the test analysis suffered from a lack of production rate or flowing pressure data during the three-month production period prior to the well test. Estimates of the rates prior to the well test were made in order to obtain the best possible test analysis. However, the fracture half-length and permeability obtained from the analysis are dependent on the assumed pre-test production rate. The permeability is estimated to be 0.02 md, the fracture half-length is estimated to be 726 ft and the well appears to drain 82 acres for an Original Gas In Place (OGIP) of 1 BCF. Figures 4 to 8 present the Cartesian, semi-log and log-log plots of the pressure response, the analysis match, and the diagnostic plots. Figure 9 presents a plot of the production history. The type-curve match and calculations are summarized in Table 1.

The Warren McMillen #1, also had bottom-hole pressures monitored during a 24-hour draw-down prior to a 240-hour build-up. The production rate prior to the build-up was reported to be 1.3 MMSCF/Day. No reasonable analysis could be made using this rate, so the historic, monthly production data was used to estimate a production rate of 0.20 MMscf/Day immediately prior to the well test. The permeability is estimated to be 0.64 md, the fracture half-length is estimated to be 670 ft. The rather short test duration and the presence of small, high permeability streaks may be influencing the test to indicate relatively high permeability. Figures 10 to 14 present the Cartesian, semi-log and log-log plots of the pressure response, the analysis match and the diagnostic plots.

TABLE 1

Type-Curve Match Point Using Infinite Conductivity Vertical Fracture Production
(Cox, 1996)

Jack C. Noel #1

Match Point

t	=	88.240681 months
q	=	102.543035 Mscf/Day
X_w/X_f	=	1.35
Pressure	=	1500 psia
z	=	0.86572009
Temperature	=	170 °F
h	=	34 ft.
B_g	=	0.0102863 RCF/SCF
delta m(p)	=	170169085
μ	=	0.015 cp
Ct	=	0.00073118 psi ⁻¹
Hydrocarbon ϕ	=	0.05
cum	=	430.367 MMscf

Calculated Values

k	=	0.01590 md
X_f	=	700 ft.
OGIP	=	590.35 MMscf
X_e	=	945 ft.
area	=	82.0 acres
Recovery %	=	72.90%

Discussion

The Terry Sandstone in the Hambert-Aristocrat Field is considered to be a shore face deposit (Appendix A). Core and log studies indicate the sand is composed of a thick (typically 10' - 40', maximum 60') basal sand with a bioturbated upper sand/shale sequence. Generally, over the Hambert Field, the total thickness is approximately 100'. Profile permeameter measurements on a single core indicate permeabilities are in the range of 0.1 to 0.001 md, although thin (1' - 5') streaks have millidarcy permeability (Appendix D and (Araujo, 1995)).

Warren McMillen #1

The Warren McMillen #1 was drilled and completed in May, 1976. Four and one half inch casing was set through the Terry. Perforations were shot from 4396' to 4448' (4 spf), and broken down with 500 gallons of mud acid. An un-monitored 24-hour build-up was conducted prior to fracture stimulation. A single-bottom hole pressure was reported to be 1768 psia. The well was fractured with 261,408 gallons and 528,600 pounds of sand. Fracture fluid was Halliburton's Super Emulsifrac (2 parts oil to 1 part water). The well's initial potential was reported to the Colorado Oil and Gas Commission as 5.8 MMSCF/D with 117 BO and 88 BW. The produced oil and water were reported to be fracture fluid. Historic production records show actual production averaged 2.7 MMSCF/D during the first month of production (July, 1976). The well was produced continually until the pressure build-up was run in February, 1978.

The electric and density logs indicate approximately 54' of pay. Porosity and water saturation are approximately 12% and 50%, respectively. Additionally, two high permeability streaks may be present in the intervals of 4396' to 4408' and 4436" to 4442'. The apparent layering complicates the well test analysis.

The pressure build-up data was reported in the form of a hand-written table in the well file. The production rate prior to the test was reported to be 1.3 MMSCF/D. The data was entered into a well test analysis program and the typical diagnostic plots were made. Initially, the high rate and lack of production history prior to the build-up made a reasonable analysis impossible. The production history was used to calculate monthly rates for the 20 months of production prior to the test. A final rate of 200 MSCF/D was used in the analysis. Use of the multi-rate history smoothed the derivative curve on the log-log diagnostic plot. Also, a 0.25 hour adjustment was made to the shut-in time to correct a small discrepancy in the early part of the pressure build-up history. Figures 13 and 14 present the log-log diagnostic plots before and after correcting the time and pressure data. The "corrected" data plots indicated a finite conductivity model should be used. A type-curve match was made to obtain initial estimates of k , x_f , P^* , and F_{CD} . A regression analysis was used to "fine-tune" the values.

The type curve used to estimate reservoir volume from the production data is based on the assumption of infinite conductivity fractures. Since the analysis indicates finite conductivity behavior, no estimate of the reservoir volume was possible.

Jack C. Noel #1

The Jack C. Noel #1 was drilled and completed in November 1978. Four and one-half inch casing was set through the Terry. Perforations were shot from 4404' to 4426' and immediately fracture stimulated with 291,186 gallons of frac fluid and 631,058 pounds of sand. The fracturing fluid was Halliburton's Acid Emulsifrac. The initial potential was reported to the Colorado Oil and Gas Commission as 910 MSCF/D with 7 BO and 3 BW. The well was produced from January until April 25th when it was shut-in for the buildup. Initial production averaged 515 MSCF/D during January and was down to 186 MSCF/D in April.

The electric and density logs indicate approximately 34' of pay. Porosity and water saturation are approximately 12% and 50%, respectively. The well logs show 2 layers. The lower layer, 4384' to 4428', has somewhat higher porosity than the upper layer which is from 4360' to 4382'. The adjacent bed effects mask the electric log response, but the density log indicates several high porosity streaks may exist in the basal sand.

The pressure build-up was recorded by Cable Drilling, Temperature and Well Servicing Company and reported on typical, typed report of readings taken from an Amerada Gauge. Initial run-in pressures of 1,000 psi were reported along with initial flowing pressures of 500 psi. Flowing pressures varied between 440 and 500 psi during the 24 hour period prior to shut-in. Rates during the period immediately before and during the flow test were estimated from the reported monthly production data. A one and one-half hour shut-in was used for the time required to run the pressure bomb. The data was entered into a well test analysis program and the typical diagnostic plots were made. A two-hour adjustment to shut-in time was made to correct an apparent abnormality in the derivative response. The "corrected" data indicated infinite conductivity fracture behavior. Figures 7 and 8 present the log-log diagnostic plots before and after correcting the time and pressure data. On this test, the Horner plot was used to estimate reservoir permeability and pressure. The regression analysis was then used to calculate fracture half-length and skin and to improve the estimates of permeability and pressure.

Production type-curves for the Infinite Conductivity Vertical Fracture were used to estimate the drainage area. The drainage area was estimated to be 82 acres. Using the log derived values and the cumulative production of 430 Mmscf, the estimated recovery is 73%.

General Comments

The lack of detailed rate histories prior to the build-ups and the relatively short build-up time on the McMillen #1 make the analysis somewhat suspect. Since both wells were apparently "floating" on line pressure, neither constant rates nor constant bottom hole pressures were maintained. Both conditions demand the use of a multi-rate analysis.

Both pressure build-ups reported initial pressures at one-half hour intervals. More frequent pressures would help define the early behavior and lend more confidence in the model selected.

Conclusions - Well Test Analysis

The layered nature and low permeability of the Terry Formation make the well tests difficult to analyze. The variable production rates prior to the build-ups add complexity to the pressure signal, but multi-rate analysis can compensate for this problem if the rate data is available. The relatively short test duration and lack of rate data make the Warren McMillen #1 analysis extremely suspect. The long build-up on the Jack C. Noel #1 lends more confidence to the analysis, but the lack of rate history prior to the test detracts from the certainty of the analysis. Regardless of the data problems, it is apparent that reservoir matrix permeability is approximately in the range of 0.01 to 0.6 md in the regions around the well tests. The large variation in apparent reservoir permeability suggests large scale heterogeneity exists in the Terry formation. The apparent variation presents challenges in optimizing the completion design on future wells. Understanding the causes of the permeability variation and more important, predicting it would assist in designing future well completions. The fracture treatments apparently are yielding fracture half-lengths of approximately 700 ft.

The interpretation results and reservoir parameters used in the analysis are summarized below:

Interpretation Results

Well Name	Permeability md	Fracture Half-Length feet
Jack C. Noel #1	0.016	730
Warren McMillen #1	<0.6	approx. 700

Reservoir Parameters Used in the Analysis

Well Name	Porosity fraction	Net Pay Feet	Sw fraction	Ct x 10 ⁶ psi ⁻¹	Temperature °F
Jack C. Noel #1	0.10	34	0.50	450	170
Warren McMillen #1	0.12	54	0.50	450	170

Production Data Analysis

The production data was analyzed to characterize the reservoir and the effective hydraulic fracture properties. Low permeability reservoirs typically exhibit a relatively long transient production period. When the producing bottom-hole pressure has been relatively constant over reasonably long periods of time, type-curve analysis can be used to obtain estimates of reservoir and hydraulic fracture properties. The method is difficult because the type-curve match is rarely unique, but knowledge of general reservoir and completion properties does assist in making an analysis. Since production data is routinely recorded, this method is applicable to nearly all wells and reservoirs. Special problems exist when production data is reported by lease rather than

individual wells. In the Hambert Field, the apparent variation in reservoir permeability complicates the use of type curves for production data analysis.

Procedure

The Hambert Field's individual lease production data was plotted on a scale which matched the scale of the Infinite Conductivity Fracture Production Type Curve (Cox et al., 1996), Fig. 15. A transparency of the type curve was overlaid on the production data plots and a "best fit" was obtained. As in using most Log-Log type curves, special care must be taken to ensure the axes on the two plots remain parallel at all times. Once the "best fit" is found, a match point is selected and the dimensionless rate time are read from the type curves and a rate and time are read from the production history plot. Then the equations presented on the type curve are used along with log derived net pay, fluid properties and estimated drawdown to calculate permeability, fracture half length and, drainage area. The calculated properties were then checked against reserves estimates and stimulation records to ensure reasonable numbers were obtained. The resulting fracture lengths and drainage areas were plotted to scale at individual well locations to visually check the drainage patterns across the reservoir. The quality checking procedures resulted in refined estimates of reservoir properties which appear to be quite reasonable.

Conclusions - Production Analysis

The production data analysis provided important feedback to the early efforts to estimating net pay. Typically, the conclusion was that the net pays from log analysis were understated. Thus from a reservoir characterization point of view, the procedure helped define the appropriate cut-off values for log-derived porosity and water saturation. This iterative procedure used the log-derived net pays, the type-curve match points, reserves estimates and plots of the estimated drainage area from the production type-curve match to refine net pay estimates.

Since production data is routinely recorded for all wells or leases, this procedure can be applied in most fields. The principal requirement is that at least some of the production history is in pseudo-steady-state. Lack of individual well production histories complicates the procedure in the Hambert Field. Drainage areas and frac lengths for individual wells can be calculated from the log-derived net pay and completion records

Well Test Methods

The production performance of an individual well or a reservoir depends on well completion geometry; reservoir characteristics such as permeability, net pay, porosity, and compressibility; reservoir fluid properties; and production operation practices. Since the economic value of a well, or field, is directly related to the production performance, characterizing and understanding the individual components influencing the performance is important to optimize the value. Specifically, the question of whether a well, or field, is producing such that the maximum net present value is realized cannot be answered conclusively without characterizing the factors which affect its performance. However, the methods used to analyze the production performance must

be cost effective. Ideally, the methods would depend on routinely available data and would be reasonably quick to implement.

Several techniques which allow characterization of well geometry and reservoir properties from detailed production history have been developed. Specifically, numerical reservoir simulation; a graphical simulation technique based on an analytical model; super-position of an exact analytical model; an approximate analytical model technique; and type curves have all been proposed, and accepted to some degree, as methods to examine the production histories of wells. The methods can be considered multi-rate well testing techniques since most of the methods specifically accept varying production rates and pressures over time and are intended to characterize the transient and steady-state or pseudo-steady-state behavior of a well. All the methods are based on solutions to the diffusivity equation. They all depend on readily available production data, i.e. producing rates, although some relatively inexpensive additional data, producing pressure, can improve the accuracy of the analyses. The following sections discuss the individual methods including data requirements and provide example analyses. The techniques presented are oriented toward hydraulically fracture stimulated wells since all the wells in the Lambert Field are stimulated, but the methods are not limited to these wells.

Regardless of the method used to analyze the production history, the basic data requirements are similar. Daily production rate and pressure data allow early estimation of well geometry and reservoir permeability. Surface pressure data are usually sufficient, but periodic bottom-hole pressures improve the accuracy of an analysis. Accurate description of the fluid properties is required since fluid viscosity and expansion are as significant as reservoir permeability in obtaining an accurate description of reservoir properties. Geologic characterization of the reservoir along with porosity and water saturation is required to select the appropriate analysis method. Finally, the general well geometry, whether it is stimulated or not, and completion configuration is needed to select an appropriate model. With the above specified data, reasonable estimates of reservoir permeability and well geometry can be obtained frequently.

The following presents a summary of well test methods including, numerical reservoir simulation, the graphical well simulation technique, inverse decline curves (IDC), and superposition. This is followed by example applications of the three analytical methods: the graphical well simulation technique, inverse decline curves, and superposition.

Numerical Reservoir Simulation

Single well numerical reservoir simulation is, perhaps, the most flexible tool currently available for analyzing production data. The flexibility adds complexity which can make it prohibitively expensive in terms of required data and analysis time. However, if reasonable simplifying assumptions can be made about the reservoir and well geometry, numerical simulation can provide an excellent means of analyzing production data.

The data requirements for simulation include specifying rock and fluid properties throughout a grid, or mesh, which represents the reservoir and well. Since several different grid systems are available (Cartesian, radial, etc.), one of the first assumptions is on what gridding system is

appropriate. Since the grid describes the physical dimensions of the reservoir and well, selection of an appropriate grid is fundamental to a successful simulation study. Automated gridding systems can speed model initialization so that an engineer can efficiently investigate the validity of a selected model. The complexity of the selected grid also affects the speed of model execution with larger, more complex grids taking longer for each history match run.

Also, the fluid system required in the model can be a major factor in model complexity. Single-phase systems, such as a normal gas or a black oil above the bubble-point pressure, do not require relative permeability or capillary pressure to be modeled so the history match runs are faster than multi-phase systems. Since multi-phase systems require modeling relative permeability, obtaining a history match is more difficult.

Once the initial estimates of reservoir properties are entered, the production rates over time are specified and the model is run. The resulting computed pressures are compared to the actual observed pressures. The reservoir and well parameters are changed and the model is re-run until the computed pressures match the observed pressures. Obtaining a unique set of match parameters can be difficult. Inclusion of pressure build-up data can help make the history match unique. The matching procedure can be time consuming, depending on the complexity of the model, the efficiency of the data manipulation, and the skill of the engineer.

Numerical methods used in reservoir simulation pose a problem absent in other multi-rate, production history analysis methods. The fine grid-blocks required to adequately model the well pressures and the short time-steps lead to problems with numerical dispersion. Dispersion can cause the pressure disturbance to reach a boundary in the model sooner than it would in a real, physical setting, and is more of a problem when simulating low permeability reservoirs.

One of the strengths of numerical simulation is that it can provide the best description of pressure-dependent properties as pressure gradients develop in the reservoir. Since the model describes a physical space with properties assigned and calculated at discrete points in time, fluid and rock properties can vary over space and time. Accurate description of the pressure distribution and fluid properties is somewhat more problematic in the analytical models which are discussed later.

A Graphical Well Simulator

A particularly useful analytical solution to the diffusivity equation has been presented by Crafton (1996)). The solution allows production rate and pressure to vary over time, so it is valuable in the analysis of production data. Another unique part of the analysis method developed by Crafton is the use of three different ways of plotting the production data so that transient and pseudo-steady-state behavior are easily identified and the observed slopes are useful in determining reservoir properties. The unique group of plots is the basis of calling it a graphical well simulator.

The data required include rock and fluid property estimates. Typically, fluid properties are generated from observed fluid gravity's, although laboratory measured data should be used when

available. Presently, the technique is best applied to single-phase systems, but useful data can be derived from analysis of oil systems below the bubble point. Periodic production rate and pressure data complete the data requirements, although the method can be used even if exact pressure data are not available. As with numerical simulation, a geologic description can assist in making the analysis.

The method involves calculating a "reciprocal productivity index" (RPI) at each reported production rate and pressure point along with calculating the dimensionless pressure and time. The RPI consists of the observed production rate divided into the change in potential from initial reservoir potential to the well-bore potential. The potential is a function of the pressure and fluid properties at that pressure, similar to the well known real-gas pseudo-pressure. Then the RPI is plotted versus time and the log of time. The RPI plotted versus the log of time is analogous to a Miller-Dyes-Hutchinson plot and the transient slope is diagnostic of reservoir permeability. The log of time plot is useful in estimating hydraulic fracture length or near-well-bore skin. The RPI plotted versus time will present a straight line during pseudo-steady-state flow, so that behavior is easily identified. The dimensionless parameters, pressure and time, are plotted on a composite of type curves presented by Agarwal and Gringarten in order to verify well geometry and reservoir area parameters.

A separate, but integral, part of the analysis method is calculating a predicted RPI at each observed data point. The model parameters such as permeability, hydraulic fracture half-length, net pay, skin, and drained area, are varied until the predicted RPI matches the observed RPI. The plots suggested by Crafton highlight the effect of specific reservoir parameters so that frequently a match can be obtained quickly.

Care must be taken in the analysis of production data with shut-in periods. Depending on the nature of the reservoir, superposition of a portion of the production data may be required to accurately model the shut-in periods.

The strength of the method is the clear identification of the transient and pseudo-steady-state flow regime. Also, the multiple plots provide a check for consistency in the analysis. The method is inexpensive computationally and does not suffer from the numerical solution problems that can hinder finite-difference reservoir simulation.

The Inverse Decline Curve (IDC)

The IDC method, as presented by Rietman (1995)), is based on a constant terminal-pressure solution to the diffusivity equation. Similar to the RPI method, transient and pseudo-steady-state flow periods can be identified readily. The method can yield estimates of reservoir permeability, drainage area, and skin or hydraulic fracture length.

Data requirements are similar to the RPI method, but periodic pressure data are not utilized. The method includes plotting the inverse of rate versus the log of time and looking for trends in the data. An early-time straight line, diagnostic of skin and permeability, should precede a transition to a late-time, pseudo-steady-state trend. A model IDC is also calculated from

estimated reservoir properties and the predicted IDC is compared to the observed IDC. As in the other analysis methods, the reservoir and well parameters are varied until the predicted values match the observed values.

Since the model assumes a constant well pressure, variations in actual producing pressure manifest themselves as noise in the observed IDC curve. Excessive noise levels can present interpretation problems. Since pressure data are not required, the method is useful in analyses of production histories which do not have pressure data available.

Superposition

The superposition method uses a constant-rate solution to the diffusivity equation. Individual rates for a given set of time periods are superposed so that the cumulative transient effect can be calculated at the well. The method is exact, but cumbersome to implement and is best suited to single-phase reservoirs.

The data requirements are similar to the RPI method. The method plots predicted and observed pressures versus time on a Cartesian scale. The reservoir and well properties are varied until a match is obtained. As with numerical simulation, a unique match can be difficult to determine. Regression techniques have been developed to automatically determine reservoir and well parameters.

The computational side of the method requires solution of an equation that adds a term for every pressure step. With long production histories, the computations may be as expensive as numerical simulation. The nature of pressure versus time data does not lend itself to determining unique solutions for a history match.

Examples

Examples of the three analytical methods are presented following this text. First, production data from two Hambert Field wells are analyzed using the RPI method. The two examples are production data from a gas well and an oil well in the Hambert Field. Since observed production pressures were not available, pressure data from the full-field simulation was used along with the observed production history. Following the real-data examples, in order to test the previously mentioned analysis methods, finite-difference reservoir simulation of a gas reservoir was used to develop example cases with known parameters. The reservoir simulation model used very fine gridding to approximate the performance of hydraulically stimulated wells. Production data was developed, then each analysis method was applied to the generated data. The simulated production histories included varying production rates and pressures. Table 2 lists the input reservoir and well parameters.

TABLE 2

Simulated Reservoir and Well Data

Initial Pressure (psi)	1,600
Net Pay (ft)	20
Model Spacing (acres)	160
Permeability (md)	0.5
Porosity (fraction)	0.12
Water Saturation (fraction)	0.45
Temperature ($^{\circ}$ F)	170
Fracture Half-Length (ft)	240
Fracture Conductivity (Dimensionless)	10

Figure 16 is the full RPI analysis of approximately 650 days of production from a gas well in the Hambert Field, well 9032. The straight line trend of the early data on the transient performance plot is diagnostic of permeability, skin, and fracture length. The slope of that portion of the curve defines the permeability while the y-intercept of the trend is indicative of fracture length and skin. The pseudo-steady-state plot exhibits a late-time, straight line which is diagnostic of drainage area. The RPI derived permeability, 0.674 md, compares to a permeability of 1.7 md (average permeability in the direction of maximum permeability) assigned in the simulator. The modeled area, 500 acres, is somewhat larger than expected. A maximum of 320 acres would be more reasonable considering the development history in the area. In other words, there were no offsetting wells to limit the volume drained by this well. The fracture length estimate is made only to demonstrate the model capabilities, since a hydraulic fracture was not imposed on the well model used in the full-field reservoir simulation.

Figure 17 is the full RPI analysis of approximately 360 days of production from an oil well in the Hambert Field, well 9552. As in Fig. 16, the straight line trend of the early data on the transient performance plot is diagnostic of permeability, skin, and fracture length. The slope of that portion of the curve defines the permeability while the y-intercept of the trend is indicative of fracture length and skin. The difference seen between the observed and model predicted trends is typical for systems, such as oil, that have fluid properties that vary greatly from the well to the reservoir boundaries. The very early data provides the most accurate prediction of permeability. The pseudo-steady-state plot may exhibit a late-time, straight line but more data is needed to be conclusive. The RPI derived permeability, 5 md, is close to the permeability of 4.3 md (average permeability in direction of maximum permeability) assigned in the simulator. The modeled area, 10 acres, is smaller than expected. Based on the development history 40 acres would be a more reasonable estimate. However, as previously noted, more data is needed to determine drainage area conclusively. The fracture length estimate is made only to demonstrate the model capabilities, since a hydraulic fracture was not imposed on the well model used in the full-field reservoir simulation.

Figure 18 presents the full RPI analysis for approximately 1,110 days of simulated daily production history from a hydraulic fracture stimulated well in a gas reservoir. The straight line

trend of the early data on the transient performance plot is diagnostic of permeability, skin, and fracture length. The slope of that portion of the curve defines the permeability while the y-intercept of the trend is indicative of fracture length and skin. The pseudo-steady-state plot exhibits a late-time, straight line which is diagnostic of drainage area. The divergence between the observed and predicted curves during the transition from early to late time may result from dispersion in the numerical model. The composite Agarwal-Gringarten type-curve plot confirms the diagnosis of a restricted fracture conductivity and drainage area of 160 acres ($X_e/X_f = 5$).

Figure 19 presents the same simulated production history, except the analysis utilized monthly reports of produced volumes and rates. The analysis produces results similar to the daily production data analysis demonstrated in Fig. 18. However, since a longer production history is presented, an anomaly can be noted in the late time data. The slope of the curve on the type-curve plot does not follow the trend of the type-curves which may indicate a problem in fluid properties used in the analysis. The model used in this analysis did not correct the fluid properties for pressure depletion, so the calculated dimensionless parameters have some inherent error at late times. A more rigorous model implementation is recommended for analyses of properties with significant depletion.

Figure 20 presents a model run which demonstrates the ability of the RPI method to identify reservoir geometry. Several keys are present in the plots which allow the diagnosis of the reservoir geometry. The first key is the type-curve plot. The calculated dimensionless pressure will follow the half-slope line. The transient and pseudo-steady-state plots exhibit trends which do not follow the radial model matches for extended periods. They may exhibit limited radial response for the period prior to the pressure disturbance encountering the initial linear limits.

Figure 21 is an IDC analysis of "perfect" production data. No pressure variations were allowed in the production data. Figure 22 is an IDC analysis of the same data used in Fig. 18. The IDC matches appear to be less exact than the RPI analyses.

Figure 23 is a superposition analysis of a portion of the data used in Fig. 18. The superposition technique used a radial model with specified rates and a calculated skin to match the observed pressures. An exact match is always achieved, but it is not unique.

Conclusions and Recommendations - Well Test Methods

Detailed production data can be used to estimate reservoir properties. Collection of frequent (daily, if possible) rates and wellhead pressures is essential to making early, efficient determination of the reservoir and well parameters. Typically, reservoir permeability and skin (or fracture length) can be determined with as little as 45 to 90 days of good quality production data. The producing time required to determine area drained by a given well depends on the compressibility, permeability, viscosity and, of course, the reservoir area. Considering that most of the Hambert Field is in contact with a gas cap and therefore has high compressibility, the time required to determine drained area could be two years or longer. The basic data requirements are generally not prohibitively expensive, in fact they are the data that are routinely collected.

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Fig. 1 Well test location map and focus area.

CSM/DOE - SUSSEX
Preliminary Work Product
Contract No. DE-AC22-93BC14891
Task 1.1.2

SPONSOR	AMOCO PRODUCTION COMPANY
WELL	JACK C. NOEL UNIT #1
SEALITY	WELD
STATE	COLORADO
DEPTH	4300.0 - 4500.0
Date Acquired	07/04/93
Well Number	DE-123-56867
WELL	WELL
Processed Date	08/16/1994 13:32

Fig. 2 Log suite for Jack C. Noel #1.

CSM/DOE - SUSSEX
Preliminary Work Product
Contract No. DE-AC22-83BC14881

Task 1.1.2

OPERATOR	AFCD PRODUCTION COMPANY
WELL	WARREN MCMILLEN #1
COUNTRY	USA
STATE	OKLAHOMA
FIELD	CSM-0 - 4888.0
Date Logged	04/22/90
Log Number	00-150-0010
LOG	4746.8
PROCESSED DATE	08/18/1994 12:33

Fig. 3 Log suite for Warren McMillen #1.

Fig. 4 Noel #1 pressure response and match.

Radial Flow Plot

Fig. 5 Noel #1 pressure response and match.

Fig. 6 Noel #1 pressure response and match.

Fig. 7 Noel #1 diagnostic plot.

Type Curve Plot

Fig. 8 Noel #1 "corrected" diagnostic plot.

Fig. 9 Production history for the Jack C. Noel #1.

Cartesian Plot

Fig. 10 McMillen #1 pressure response and match.

Fig. 11 McMillen #1 pressure response and match.

Log-Log Plot

Quick Match Results		
Vertical fracture - finite conductivity		
Infinitely acting		
Cs	= 0.0015	bb/psi
K	= 0.6439	md
Sf	= 3.182e-006	
Xf	= 671.655	ft
Fcd	= 8.017	
D	= 6.177e-004	1/(Mscf/day)
PI	= 1084.9672	psia

Delta m(p) / Delta Q (psia²/cp (*1E-06) / MMscf/day

Equivalent Time (hours)

Fig. 12 McMillen #1 pressure response and match.

Fig. 13 McMullen #1 diagnostic plot.

Type Curve Plot

Fig. 14 McMillen #1 "corrected" diagnostic plot.

Fig. 15 Infinite conductivity fracture production type curve.

Well: Hambert - 9032

Production Decline Curve

Composite Agarwal-Gringarten Type Curves

Transient Performance Plot

Pseudo-Steady State Performance Plot

Reservoir Parameters:

Permeability	0.674 md
Skin	0.0
X_f	110 ft
Area	500 ac
Net Pay	18 ft
Hydrocarbon Porosity	0.032 fraction
Initial Pressure	1652 psi
Reservoir Geometry	Radial

Fig. 16 RPI analysis for well 9032, gas well with 650 days of production.

Well: Hambert - 9552

Reservoir Parameters:

Permeability	5 md	Net Pay	34 ft
Skin	0.0	Hydrocarbon Porosity	0.052 fraction
X_i	60 ft	Initial Pressure	1637 psi
Area	10 ac	Reservoir Geometry	Radial

Fig. 17 RPI analysis of well 9552, oil well with 360 days of production.

Reservoir Parameters:

Permeability	0.6 md	Net Pay	20 ft
Skin	0.4	Hydrocarbon Porosity	0.066 fraction
X_i	240 ft	Initial Pressure	1607 psi
Area	160 ac	Reservoir Geometry	Radial

Fig. 18 RPI analysis of simulated production, gas well 1110 days of production.

Well: DOE - Prod0002

Production Decline Curve

Composite Agarwal-Gringarten Type Curves

Transient Performance Plot

Pseudo-Steady State Performance Plot

Reservoir Parameters:

Permeability	0.5 md	Net Pay	20 ft
Skin	0.5	Hydrocarbon Porosity	0.066 fraction
X_f	240 ft	Initial Pressure	1607 psi
Area	160 ac	Reservoir Geometry	Radial

Fig. 19 RPI analysis of simulated production, gas well 90 months of production.

Well: DOE - Prod0005

Reservoir Parameters:

Permeability	0.5 md	Net Pay	20 ft
Skin	0.3	Hydrocarbon Porosity	0.066 fraction
X_i	325 ft	Initial Pressure	1607 psi
Area	320 ac	Reservoir Geometry	Linear

Fig. 20 RPI analysis, linear reservoir geometry.

IDC Analysis

Fig. 21 IDC analysis of perfect production data.

IDC Analysis

Fig. 22 IDC analysis of data used in Fig. 18.

Superposition History Match

Fig. 23 Superposition analysis of data used in Fig. 18.

Appendix F

Reservoir Engineering Evaluation - Pre-Full Field Simulation

by

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Introduction

This report documents the reservoir engineering work performed prior to full field simulation. The well information, well activity, and production data are as of August 1993. Later in the project the production data was updated and recompletions were added to the database through August 1995.

Figure 1 outlines the Hambert-Aristocrat study area which encompasses 54 leases with 62 wells producing from the Terry formation. Cumulative production is 24.8 billion standard cubic feet (SCF) of gas and 1.0 million stock tank barrels of oil (STBO). Production was initiated in 1972. Again this information is through August 1993.

From a reservoir engineering perspective, low permeability, heterogeneous reservoirs present some unique difficulties for production and analysis. Extremely long well tests may be required to obtain useful pressure data. Representative fluid samples are difficult to obtain since large pressure drawdowns are required to maintain stabilized flow. Traditional analytical tools such as the material balance approach and decline curve analysis must be used with great care since large uncertainties can exist in determining average reservoir pressure, fluid properties, and flow regimes. Frequently data gathering for low permeability reservoirs is limited to the state regulatory agency's minimum requirements since production rates and the associated cash flows are relatively low. Since cash flows are limited, a low operating overhead must be maintained for the properties to be profitable. The net result is that a field is typically operated with a minimum of data gathered and minimal analysis of that data.

The following sections document the development history of the area, pressure and fluid data, the results of early material balance calculations, completion strategies, interpretation of areal fluid distributions and potential sealing faults.

Development History

The first four wells drilled and completed in the Terry sand in or around the focus study area (Township 65W) are:

Range	Section	Well API No.	Compl/ Ini.Prod mm/yy	Initial GOR scf/bbl	Cum Oil MSTB	Cum Gas MMSCF	Last Produc. Report
4N	34	07470	06/72	No production history			
4N	15	07507	09/72	Shut in or Temporarily Abandoned			
4N	29	11962	10/73	1,200	108.1	206.4	09/93
3N	6	07265	10/74	>50,000	2.4	216.1	09/93

No other wells were drilled and completed in the Terry until 1975. During 1975 and 1976, only the following six wells were drilled and completed in the Terry sand.

Range	Section	Well API No.	Start Produc. mm/yy	Initial GOR scf/bbl	Cum Oil MSTB	Cum Gas MMSCF	Last Prod Rep
4N	19	09452	12/75	>50,000	21.2	2653.4	9/93
4N	32	08670	04/76	no production history report			
4N	32	10582	06/76	<10,000	6.5	377.1	9/93
4N	18	07545	07/76				
4N	18	08867	12/76	no production history report			
4N	30	09734	12/76	>50,000	2.4	216.1	09/93

Most of the development was performed during the next three years (1977, 1978 and 1979) with a total of 24 wells drilled and completed in the Terry sand. By the end of 1979, most of the sections in the study area were developed.

During the 1980's, 22 wells were drilled and completed. Ten of these wells were infill wells in the sections already in production and 12 were to extend the production to the east of the focus area (sections 9, 16, 28 and 33 of range 4N and sections 3 and 4 of range 3N).

Beginning in 1990 until August 1993, 11 wells were drilled and completed in the Terry sand or commingled in the Terry and deeper formations, usually the Niobrara and Codell.

The information on the above wells was available for the analysis. Later in the project the activity for the period 8/93 to 8/95 was gathered and input into the data base. During this period there were approximately 45 Terry re-completions. Most of the wells added during the period were initially Codell-Niobrara completions. The Terry interval was perforated, fracture stimulated, and commingled with the Codell-Niobrara production in these cases. In some cases the Terry zone was tested before commingling with the Codell-Niobrara. However in many cases it was not. **In general, there is a large amount of uncertainty in allocating production to specific intervals in a well. This uncertainty is further compounded by the necessity in some cases to allocate multi-well lease production to individual wells.**

This brings the total number of wells in the study area to 101

PVT and Pressure Data

The material balance approach requires information about the volume of produced fluids, fluid properties data, and initial and periodic average reservoir pressures. Additional data such as volumetric information can be used to enhance the quantity and accuracy of the results of the material balance calculations. With sufficient data, it is possible to estimate volumes of produced fluids which may not have been recorded because of production practices, such as unmetered water disposal, or uncontrolled flows (blowouts).

Pressure Data

Initial pressures are usually obtained from pressure build-up tests conducted during or soon after a well's completion. These tests are particularly important for the first few wells in a field since it may be the only opportunity to directly measure the initial field pressure. In low permeability and/or extremely heterogeneous reservoirs, a well test may not yield enough data to determine the initial reservoir pressure because the required shut-in times are too long. However, recently methods have been presented (Raghaven & Chu, 1996) which may help resolve the difficulty in estimating the average pressure from well tests in low permeability reservoirs. That is, it appears to cost too much in terms of deferred production to shut in the well long enough to obtain the desired data. This is the case for the Hambert-Aristocrat field, where an accurate initial reservoir pressure is difficult to determine from the available information.

Using the normal water gradient of 0.433 psi/ft and the estimated gas oil contact at 4600 feet and some free gas present in well 9552 provides an estimated initial pressure of 1991.8 psi. Evaluations of the well test data from the Jack C. Noel #1, the Warren McMillen #1 (Appendix E), and 15 day post-completion flow records for 6 other wells indicate the initial reservoir pressure is greater than 1,500 psia and less than 2,000 psia.

Information from the earliest wells provides additional clues. The following list summarizes the earliest found pressure data:

Section	Well	Test Date	Type	Max Pressure	Gauge Depth	Extrapolated Pressure
17	08658	05/11/76	B.U.	1572	4422	
19	08658	01/20/78	B.U.	742	4422	1312
20	08867	04/25/77	B.U.	997	4350	1391
31	09691	09/07/78				
31	09691	07/22/79				

The maximum known pressure of 1,768 psig (well 8658) was recorded in April 1976 at a depth of 4,422 feet. This pressure was recorded before fracture stimulation with the completion fluid still in the well. It was noted that the well was on a vacuum. A second pressure of 1,572 psig was recorded after fracture stimulation and well clean up. **Based on this information, the initial reservoir pressure is estimated to be between 1,600 - 1,750 psia and equal to the bubble-point pressure. The initial pressure may be different for each fault block because the gas-oil contacts (GOCs) are at different depths. The uncertainty of the estimates may narrow during history matching.**

Many fields have annual field wide shut-ins to monitor pressure. Some gas fields have yearly one-point flow tests which can be used to help estimate reservoir pressures. The Hambert and Aristocrat fields do not have field wide shut-ins or one-point tests although one operator ran sporadic one-point tests in the early 1980's. There is one well, the Homestead #1, completed in the Terry formation near the study area which is currently

produced only one hour each week. Its bottom-hole pressure is approximately 1,000 psi, and the well has a production history similar to wells in the study area. This 1,000 psi is being used as an estimate of the current reservoir pressure.

Fluid Properties

Since no fluid analyses are available, reservoir fluid characterization for the study area must be based upon correlations. In general, correlations are developed from a large number of fluid samples which have been characterized. The resulting data are analyzed to develop the correlations. Ideally, correlations specific for the area of a field study will be available. Unfortunately, no correlations are available for our field of interest, so general correlations were used in the engineering calculations.

Only a few wells reported the API gravity of the oil produced. The following table presents a summary of the oil API from the production history reports. Based on this information and the plot of API versus GOR of Fig. 2, an average of 51 ° API gravity was calculated to represent a value for the oil in the Terry sand of the Hambert Field.

Section	Well	Initial	Initial GOR	Gas Gravity	Oil API
31	12874	04/86	2,200		49.5
31	09552	04/78	3,000		53
32	09739	04/79	1,800		51.1
5	09637	01/79	9,000		50
18	09580	01/77	15,000		53
33	12174	01/85	10,000	0.8008	45

With the 51 °API oil and a gas gravity of 0.8 Standing's correlation suggests the following alternatives for the initial gas in solution:

Bubble Point Pb (psi)	1,700	2,000	2,134
Gas in Solution Rs (scf/bbl)	757	921	1,000

Based on several PVT correlations the upper estimate for initial solution GOR is assumed to be 750 SCF/BBL. Keep in mind that initial pressure is equal to bubble point pressure.

Material Balance

The material balance approach has been used to investigate the study focus area. Oil, gas, and water production data from Dwights Production CD were used to determine total production from the Terry formation. Production from commingled wells was assigned to a formation on the basis of reported initial potentials when better information

was not available. Since a portion of the study area is considered to be a wet gas reservoir, liquid hydrocarbon production from the wells in that area was converted to an equivalent gas volume. The gas production from the oil leg of the reservoir was assumed to be mostly solution gas. Two gross reservoir models have been considered, separate gas and oil reservoirs, and an oil reservoir with a large gas cap.

The original gas in place (OGIP) is estimated to be approximately 60 BSCF. Both the P/Z plot (independent gas reservoir model) and the large gas cap material balance model agree reasonably well. Using the remaining reserves estimates and the P/Z plot, abandonment pressure is estimated to be 850 psi. Of course, since the pressure data are so sparse, these estimates are tentative. Further use of volumetric information from log analysis, geologic study, and geophysical study will improve these estimates for OGIP and GIP at abandonment.

The original oil in place (OOIP) estimates were made from the independent oil reservoir and the large gas cap models. Because of the sparse availability of pressure data, the OOIP cannot be accurately estimated. Using very gross estimates for the size of the gas cap relative to the oil leg, the OOIP is in the range of 9 to 17 million STBO. Using the independent oil reservoir model, the OOIP estimate is in the neighborhood of 7 million STBO.

Since little water has been produced over the life of the field (165,000 bbls), and the geologic study has not suggested the presence of an aquifer, water is not considered to be a major contributor to the reservoir drive mechanism.

Completion Practices

The Terry reservoir formation is a relatively low permeability sandstone. It was initially developed on 320-acre spacing in the gas portion and 40-acre spacing in the oil portion. Several sections in the gas portion of the field are classified as tight gas by the FERC. A square or rectangular geometric pattern with wells located in the center of a quarter-quarter or half-quarter appears to be typical for wells in the area. All the wells were drilled with fresh water mud and cased through the Terry formation. The wells were completed by perforating, generally 4 shots/foot, and massive hydraulic fracture stimulations. Fracture treatment sizes ranged from approximately 50,000 gallons of fluid and 150,000 lbs of sand to 200,000 gallons of fluid and 750,000 lbs of sand. Typical fracture designs were for half-lengths of up to one thousand feet. Records of treatment design and actual treatments are very poor for pre-1990. Net fracturing pressure plots from three recent completions were used to assist analyzing completion practices.

Several questions need to be addressed when evaluating completion practices. The major goal is to maximize reservoir drainage with minimum investment. Since the completions include long fracture lengths in the tight sands, relatively long periods of linear reservoir flow may be expected. Fracture direction should play a significant role in determining the volume, extent, and shape of a reservoir drained by a well. The placement

of each well should consider the most likely fracture propagation direction and the resulting drainage shape. The nature of the reservoir rock will also play a large part in the completion design and well locations.

Typically, a relatively clean basal sand is overlain by a thicker, thinly laminated shale and sand sequence. Thick shales over and underlie the sand bodies. Some operators perforate the entire interval while other operators perforate only the basal sand. Since the volume of sand in the thinly laminated section may be substantial, wellbore communication with this portion of the reservoir is of interest.

Methods exist to estimate fracture lengths from well test or production data (Appendix E). Well test data can provide better estimates since better quality data can be obtained. Analyses of the two available well tests indicate fracture lengths approximately 60 to 80 percent of the design lengths are obtained. Analysis of the production data indicates the fractures do affect reservoir drainage areas, that is, linear flow is probably occurring for up to 10 years in the lower permeability portions of the reservoir.

Fracture propagation direction cannot yet be determined from production data and common well test data. Knowledge of the direction, or azimuth, of the fracture would allow better selection of well locations than the actual methods used in the field. Geophysical, geological, and engineering analyses can help determine the orientation of the fractures.

Fluids Distribution in the Field

The fluid distribution analysis in the field was performed based on the production history and the GOR behavior of the wells. Wells were coded according to their early GOR behavior and were classified in four main codes:

Wells with	GOR < 5,000 SCF/BBL	Oil wells
Wells with	5,000 < GOR < 10,000 SCF/BBL	Oil wells with free gas
Wells with	10,000 < GOR < 50,000 SCF/BBL	Gas wells with some oil
Wells with	50,000 > GOR	Gas wells

Based on the gas-oil ratio of the wells and its evolution during the production history, it was concluded that the fluids were distributed in two main areas: a predominantly oil area and a predominantly gas area. These main areas are separated along a diagonal south-west to north-east trend, as shown in Fig. 3.

Several wells located in the oil area have high GORs compared with what should be expected from an oil well. Several different possible causes or combinations were considered. Among them are: the structural position of the producing interval and the

possibility that the sand has oil with an initial gas cap, the possibility of open layers that include a gas layer, or a combination of the above mentioned cases.

The mentioned alternatives suggest the inclusion of vertical fluid distributions in addition to the areal distribution. **Sealing faults between wells could be the cause of having the presence of gas and oil at similar levels of the reservoir. Therefore, it is believed that there is compartmentalization.**

In section 31, well 12874 has produced oil since 1986 with an initial GOR of approximately 2,200 SCF/BBL, which quickly jumped to 7,000 SCF/BBL for most of its production history. Since this well started production approximately fourteen years after the initial production of the area, it is believed that a secondary gas cap was developed as the pressure of the reservoir was depleted. Well 15426, located in the north-west corner of section 31, was completed in 1992 with an initial GOR of less than 5,000 SCF/BBL, which increased quickly to 100,000 SCF/BBL or more. This behavior suggests that the latter well probably had oil in some of the layers but not enough to maintain a lower GOR behavior. These two wells are shown on Fig. 4.

The production trends over time suggests that a main diagonal sealing fault from the south-west part to the north-east part of the field separates a predominantly oil area from a predominantly gas. A diagonal fault was observed on 3-D seismic, Fig. 5. This trend, however, is interrupted in section 21 where there seems to be a shift to the north-west of the trend line. This shift was also observed by the 3D seismic interpretation. The interpretation did not define if this is a fault or simply a change in depositional characteristics. From a geologic perspective both conditions are possible. At this point, the production characteristics could support either interpretation: a geologic change of depositional characteristics or sand quality, or a sealing fault as described above.

Initial GOR in the Oil Area

Since there were no fluid samples the only source of information to determine the initial GOR is the production history. Three key wells selected to determine the initial GOR in the oil area are wells 09553, 09673, and 11962 in section 29, Fig. 6. These wells were completed in 10/72, 10/78, and 7/79 respectively. Figures 7a, 7b, and 7c shows the GOR behavior of these three wells. The following table summarizes information for these wells:

Section	Well	Completion	Initial Production	Initial GOR	Cum. Oil	Cum. Gas	Last Report
29	11962		10/72	1,000	108.11	206.39	9/93
29	09553		10/78	1,300	57.03	52.91	9/93
29	09673	07/79	07/79	1,000	21.07	10.08	9/93

The GOR behavior of the above mentioned wells show that a value between 1,000 and 2,000 SCF/BBL predominates during the first part of the producing life. An initial solution GOR of 1,000 SCF/BBL is believed to be a reasonable estimate for the oil area based on the production history and the plots presented in Figs. 7a, 7b, and 7c.

Estimating Gas-Oil Contacts

The compartmentalization of the reservoir results in both vertical and areal distribution of fluids. Cross sections were prepared for different parts of the field. An example is shown in Fig. 8. The location of cross section A-A' is shown on the area map, Fig. 9. Cross sections were made to augment the determination of gas-oil contacts for the compartments on a depth basis. Perforated zone, GOR, and neutron density data were integrated with the structural data to estimate the gas-oil contact. For example, the higher the GOR the more the perforated zone was assumed to be saturated with gas and less with oil. The cross sections indicate that the gas is in the upper layers and the oil is predominately in lower zones within any fault block having a gas-oil contact.

Figure 10 is an example well log where the shale corrected density and neutron logs indicates a gas-oil contact. The relative amount of neutron-density separation was used to support gas-oil contact selection. Most of the wells with neutron and density logs do not have a clear separation of these two curves.

Many of the wells that had an initially low GOR (predominately oil zone) are still producing oil at reasonably low GOR values. For wells that started with an intermediate GOR value, the gas invasion is minimal and the gas-oil contact is within the perforated interval. The wells producing with high initial GOR's are in a block or region which is predominately gas, with small or no oil present. In these cases the GOR is constant at a value greater than 50,000 SCF/BBL. The cross sections indicate that the gas is in the upper layers and the oil is predominately in lower zones within any fault block having a gas-oil contact.

Barrier Analysis

The process of integrating the preliminary geologic and geophysical interpretations with production history provides support for sealing faults.

Wells 09553 and 09302, in section 29, are separated by a south-west to north-east trending fault defined by geology and 3D seismic interpretation, Fig. 11. Well 09553 is on the south-east side of the fault and produces oil with an average GOR of 2,000 SCF/BBL. Well 09302 is on the north-west side of the fault and produces gas with average GOR of 100,000 SCF/BBL. This observation could be an indication of the sealing characteristic of this fault. This fault will be called the main diagonal trend fault for future references in this report.

In the north-east, in section 20, well 14079 showed an initial average GOR of 2,000 SCF/BBL. This well was completed in 1988 and died very soon. Assuming that mechanical problems were not the cause, and observing that this well was completed near a fault, it is hypothesized that the short life is the result of the limited drainage area of the well caused by diagenetic cementing which reduced the storage capacity of the well. The evidence of calcite cementation in fractures was observed in one core (Appendix A). Well 15407 was observed to have low porosity also hypothesized to be caused by diagenetic cementing related to the faulting (Appendix B and C), Fig. 12.

Production Allocation

A significant amount of the production is commingled at the well bore (multiple zones) and at the surface (multiple well leases). This adds uncertainty to the analysis. The production was allocated using production performance before and after a well or new formation was added to the production stream. The decline curve forecast before the new production was subtracted from the decline curve performance projection after the new well or formation to estimate the incremental contribution of the new well or formation. The initial tests were also used to help in the allocation when no other data was available.

References

Raghaven, R., & Chu, W. (1996, April 28 - May 1). On the determination of reservoir pressure when radial flow conditions are nonexistent. Paper presented at the Annual Gas Technical Conference, Calgary, Alberta Canada.

Fig. 1 Hambert Field Study area showing the seismic area

Fig. 2 API gravity as a function of producing gas-oil ratio in the oil region of Hambert-Aristocrat study area.

Fig. 3 Predominantly gas and oil areas in Hambert-Aristocrat study area.

Fig. 4 Location of well 15426 (gas region, GOR >100,000) and well 12874 (oil region, GOR <7000).

Fig. 5 Location of main diagonal fault which divides the oil and gas regions and location of possible NW-SE fault from 3D seismic interpretation

Fig. 6 Location of wells used to estimate initial GOR in oil region.

Fig. 7a GOR trend for well 09553.

Fig. 7b GOR trend for well 09673.

Fig. 7c GOR trend for well 11962.

Fig. 8 Northwest-Southeast Terry Sandstone cross section A-A¹.

HambGOR/:Layer 1/Structure Tops(Ft)

Cross Section

Fig. 9 Terry structure map with cross section A-A¹.

SPOT LOCATION
1980FNL 1980 FEL 29 4N 65W

CSM/DOE - Sussex
Preliminary Work Product
Contract No. DE-AC22-93BC14891
Task 1.1.2

OPERATOR	Chaplin Petroleum Corp
COUNTRY	USA
STATE	WV
COUNTY	Putnam
WELL	4890.0
DATE	07/27/1995
LOG	14.10
LOG NUMBER	4890.0
LOG DATE	07/27/1995
LOG TIME	14.10

LOG NUMBER	08533320
LOG DATE	07/27/1995
LOG TIME	14.10
LOG	14.10
LOG DATE	07/27/1995
LOG TIME	14.10
LOG	14.10
LOG DATE	07/27/1995
LOG TIME	14.10

Fig. 10 Neutron-density curve separation used to support gas-oil contact.

Fig. 11 Wells 9302 and 9553 where GOR trends support sealing fault

Fig. 12 Wells 15407 and 14079, support for hypothesis of sealing fault caused by diagenetic cementing (low porosity).

APPENDIX G

Hambert Study Area Reservoir Simulation

by

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Introduction

The reservoir simulation phase of the Reservoir Integration Project consisted of simulation test cases, building the study area model, history matching the study area model, and running predictive cases. The test cases involved small simulations of single wells within the study area. The test cases provided indications of how the Terry reservoir behaves in the Hambert Field area. The results of these test cases were used in the development of the study area model. The study area model contained over 100 oil and gas wells. By varying reservoir properties, the simulated performance of the area was matched to that of the historical performance through history matching. The historical production was closely matched by the simulator. The predictive runs were based on the history matched numerical model of the reservoir, providing insight into future production and potential operating schemes in the study area.

The Petroleum WorkBench, an integrated software package developed by Scientific Software-Intercomp, was the primary reservoir engineering tool for this portion of the study. WorkBench, which includes Production Decline Analysis, Well Test Analysis, Reservoir Description and Reservoir Simulation modules, provides a consistent graphical user interface among its various components. The SimBest II reservoir simulator module of WorkBench is a three-dimensional, three-phase, single and dual-porosity, adaptive implicit reservoir simulator that was used for the reservoir simulation task.

Two Pentium™ 66 MHz computers performed the simulation runs. The computers were each equipped with 48 MB of RAM and 1.2 GB hard disks. Each history match run took between 12 and 14 hours to complete and consumed approximately 100 MB of disk space. Plotting the production and analyzing the individual runs took about 6 hours for each run.

Simulation Test Cases

Introduction

Several preliminary simulation cases were developed and tested before setting up the full field simulation. The preliminary investigations were designed to develop a better understanding of the relationship between the actual reservoir performance and a particular reservoir model and assumptions. Input to the test case models took advantage the analysis of the Vern Marshall (oil well case) and the Jack Noel (gas well case), Appendix F. Both single-cell and multiple-cell cases were tested. In the multiple-cell cases, real faults and other petrophysical property data obtained for each well were input into the simulation database. Analysis of the fracture length, done with an infinite conductivity fracture type-curve model based on production history, provided estimates of the average permeability of the drainage volume around the wells. Layer permeability values obtained from the petrophysical transforms were checked against the average

permeability values from the type-curve analysis to determine a better representation of the permeability values for the simulation model.

The test cases have provided gross estimates of the remaining oil at the abandonment pressure (Pab 300 psia), and an indication of the relative permeabilities based on actual production and material balance calculations. Table G-1 presents a summary of the results from the test cases.

TABLE G-1

Tank Model Results for the Oil Zone
Hambert Aristocrat Field
(One-Cell Model)

Case	Recovery						Recovery Fraction		Remaining	
	Pi to Pb		Pb to Pabd		Pi to Pabd		Oil	Gas	OIP STB	So
	Oil STB	Gas MMSCF	Oil STB	Gas MMSCF	Oil STB	Gas MMSCF				
1	-	-	805,308	4,502.5	805,308.1	4,502.5	0.0710	0.8821	10,543,521	0.4753
2	-	-	902,446	4,497.8	902,446.3	4,497.8	0.0795	0.8812	10,446,383	0.4709
3	-	-	1,002,457	4,493.0	1,002,456.6	4,493.0	0.0883	0.8802	10,346,373	0.4664
4	-	-	1,105,382	4,488.1	1,105,382.4	4,488.1	0.0974	0.8793	10,243,447	0.4618
5	-	-	1,211,326	4,483.0	1,211,325.7	4,483.0	0.1067	0.8783	10,137,504	0.4570
6	-	-	1,319,911	4,477.8	1,319,911.3	4,477.8	0.1163	0.8772	10,028,918	0.4521
7	-	-	1,431,644	4,472.4	1,431,644.1	4,472.4	0.1261	0.8762	9,917,185	0.4471
8	-	-	1,546,407	4,466.9	1,546,407.0	4,466.9	0.1363	0.8751	9,802,422	0.4419
9	-	-	1,664,392	4,461.3	1,664,392.3	4,461.3	0.1467	0.8740	9,684,437	0.4366
10	-	-	1,785,008	4,455.5	1,785,008.0	4,455.5	0.1573	0.8729	9,563,821	0.4311
11	-	-	1,908,945	4,449.6	1,908,944.8	4,449.6	0.1682	0.8717	9,439,885	0.4256
12	220,729.39	99.28	1,103,821	4,349.8	1,324,550.1	4,449.1	0.1155	0.8622	10,146,103	0.4618
13	148,370.62	66.73	1,107,386	4,395.9	1,255,756.3	4,462.6	0.1098	0.8676	10,180,877	0.4618
14	64,809.66	29.15	1,110,951	4,447.0	1,175,760.3	4,476.2	0.1032	0.8738	10,213,652	0.4618
15	-	-	1,134,266	4,197.5	1,134,266.2	4,197.5	0.0987	0.8735	10,358,358	0.4665
16	-	-	1,212,219	3,299.0	1,212,218.8	3,299.0	0.1016	0.8495	10,714,227	0.4811
17	-	-	1,077,926	4,505.7	1,077,925.8	4,505.7	0.0950	0.8827	10,270,904	0.4615
18	-	-	1,087,083	4,499.9	1,087,082.6	4,499.9	0.0958	0.8816	10,261,747	0.4616
19	-	-	1,096,334	4,494.0	1,096,333.9	4,494.0	0.0966	0.8804	10,252,495	0.4617
20	-	-	1,105,382	4,488.1	1,105,382.4	4,488.1	0.0974	0.8793	10,243,447	0.4618
21	34,146.94	14.28	1,149,570	4,171.3	1,183,716.9	4,185.6	0.1028	0.8694	10,330,784	0.4666
22	67,054.96	25.94	1,185,149	3,856.4	1,252,203.8	3,882.4	0.1072	0.8593	10,426,956	0.4714
23	98,682.00	35.13	1,219,628	3,540.9	1,318,310.0	3,576.0	0.1113	0.8482	10,524,253	0.4764
24	128,989.56	42.00	1,252,452	3,224.8	1,381,441.1	3,266.8	0.1151	0.8357	10,623,002	0.4813
25	157,943.59	46.71	1,282,508	2,908.6	1,440,451.4	2,955.3	0.1184	0.8216	10,724,058	0.4864
26	185,515.50	49.40	1,309,201	2,592.6	1,494,716.9	2,642.0	0.1213	0.8051	10,827,723	0.4917
27	211,683.42	50.26	1,330,974	2,277.3	1,542,657.7	2,327.6	0.1236	0.7856	10,935,226	0.4971
28	-	-	1,080,352	4,599.0	1,080,352.3	4,599.0	0.0951	0.8779	10,276,867	0.4611
29	-	-	1,054,045	4,712.1	1,054,045.1	4,712.1	0.0928	0.8765	10,310,248	0.4604
30	-	-	662,113	3,088.2	662,113.4	3,088.2	0.0875	0.9075	6,903,773	0.3112
31	-	-	912,970	3,786.8	912,969.7	3,786.8	0.0965	0.8902	8,544,388	0.3852
32	-	-	1,279,425	5,190.3	1,279,424.9	5,190.3	0.0966	0.8716	11,960,876	0.5192
33	-	-	635,148	4,510.6	635,148.0	4,510.6	0.0560	0.8837	10,713,681	0.4830
34	-	-	899,412	4,497.9	899,411.9	4,497.9	0.0793	0.8812	10,449,418	0.4711
35	-	-	1,321,322	4,477.7	1,321,322.3	4,477.7	0.1164	0.8772	10,027,507	0.4520
36	-	-	1,141,731	4,486.3	1,141,730.6	4,486.3	0.1006	0.8789	10,207,099	0.4601
37	-	-	1,183,688	4,484.3	1,183,687.8	4,484.3	0.1043	0.8785	10,165,142	0.4582
38	-	-	1,232,921	4,482.0	1,232,921.3	4,482.0	0.1086	0.8781	10,115,908	0.4560
39	-	-	1,291,915	4,479.1	1,291,915.1	4,479.1	0.1138	0.8775	10,056,914	0.4534
40	-	-	1,364,590	4,475.6	1,364,590.1	4,475.6	0.1207	0.8768	9,984,239	0.4501

Pb = Bubble-Point Pressure
Pabd = Abandonment Pressure
Pi = Initial Reservoir Pressure
OIP = Oil In Place (STB)
So = Oil Saturation (decimal)

Test Case Summary

1. One-cell tank model. The one-cell model provides an estimate of the remaining oil and gas in place at an assumed abandonment pressure of 300 psia. The results of the single-cell tank model compare favorably to the initial material balance calculations.
2. One-well radial model simulator without a hydraulic fracture in a single-porosity system. This model provides insight into the limitations of the reservoir under no stimulation treatment.
3. One-well Cartesian model simulator with hydraulic fracture in a single-porosity system. Two cases were investigated, a single-layer case and a five-layer case. Sensitivities to the grid size near the well bore and to the fracture width were performed. It was found that the fracture width of 2 in. works well for the one-layer model. However, for the five-layer model the fracture width must be at least 0.33 ft in order to have stable runs. Sensitivity to vertical permeability (K_z) inside the fracture was performed, in which it was determined that the larger the K_z value the longer the time for the simulation run. History matching of the well 11962 was performed for the one-layer oil case.
4. Cross-section multi-layer model in a single-porosity system. The cross-section multi-layer model with single porosity was used to evaluate the behavior of the wells under two different layering schemes. The first model lumped various layers defined by the geologic study, while the second was a more refined model with additional sub-layers.
5. The one-well hydraulically fractured oil case was matched with the production history of the well 11962 (UPPR 21 Pan Am #D 2). The one-well hydraulically fractured gas case was simulated with a five-layer model using the production history of the well 08867 (Jack Noel #1). This well also has pressure buildup data. This was compared to a single-well negative skin model to determine which would be incorporated into the final field model.

Study Area Simulation Model

Building Simulation Model

Figure G-1 shows the location of the study area. This area encompasses the area of the 3 section seismic survey. To aid in the matching of the reservoir, a buffer zone was included in the simulation grid scheme. The following sections present the study area simulation model development. While the study area does not actually include every well in the Hambert-Aristocrat field, this model is referred to herein as the full field model.

Simulation Grid

The simulation model was built with a grid of 60 cells in the X direction, 70 cells in the Y direction and 5 layers. The cells are of a constant size of 471 ft in the X direction and 410 ft. in the Y direction. The orientation of the grid follows the trend of the main faults in the field, i.e. SW-NE direction (the grid is rotated 45° from due north).

Figure G-2 shows the grid placed over the sections that cover the Focus Area. The Focus Area covers the sections 17, 20, 29, 31, 32, and 33 Township 4N, Range 65W plus a buffer zone that covers a half mile outside the sections mentioned above.

Regions

Five regions for each layer were defined based on the compartmentalization and the estimated GOC levels in the fault blocks. The initial pressure was set to 1650 psia located at the GOC. Only one type of oil and one type of gas were selected for the entire model, i.e. one PVT table for the oil and one PVT table for the gas. Table G-2 summarizes the gas-oil contact (GOC) for each of the five regions, and there were the starting points for the simulation model.

TABLE G-2
GOC Datums

REGION	Initial Pressure (psia)	GOC (ft)	Bubble Point Pressure (psia)
1	1650	282	1650
2	1650	295	1650
3	1650	335	1650
4	1650	400	1650
5	1650	295	1650

Figure G-3 shows the five regions distributed in the area covered by the simulation grid. Inactive cells are defined by all cells outside the buffer area. Wherever there is no net thickness and/or no porosity the model automatically assigns that cell as an inactive cell. Additional inactive cells were defined by a cell with a net thickness of less than 0.5 ft within the study area.

Initially the study area was split into three regions, but the highly compartmentalized nature of the Hambert Field, the result of extensive faulting, required five regions. Also as a result of history matching, minor changes were made in the relative location of some of the faults. The shift in the location of the faults were within the accuracy of the data used to estimate the location of the faults. This is an example where additional information

reduces some of the uncertainty. Also, it was determined that regions 2 and 3 are in communication and, therefore, have the same gas-oil contact (GOC).

Simulation Model Layers

The geologic description and the petrophysical analyses identified nine layers, as shown in Table G-3. The top and bottom layers were eliminated because they were shale. The identified geologic layers were combined into five layers for the reservoir simulation model. The layers for the simulation are summarized in Table G-3. Most of the wells are perforated in simulation model layers 3, 4, and 5. These layers are shown on an example Log Analysis Summary Plate, Fig. G-4.

TABLE G-3
Comparison of Geologic and Simulation Models

<u>Geologic Model</u>	<u>Descriptions</u>	<u>Simulation Model</u>
Layer 0-1	Top shale layer	Not used
Layer 1-2	Top sand body	Layer 1
Layer 2-3	Shale layer	Layer 2
Layer 3-4	Sand body	Layer 2
Layer 4-5	Shale layer	Layer 3
Layer 5-6	Sand body	Layer 3
Layer 6-7	Shaly sand body	Layer 4
Layer 7-8	Sand body	Layer 5
Layer 8-9	Shale layer	Not used

Reservoir Properties

Gross and Net Thickness

Manual mapping of geologic layers 5-6 and 7-8 were performed considering the northwest to southeast depositional trend. Computer maps were generated using petrophysical derived net thicknesses, kriging software, and the assumed depositional trend. Comparisons of the computer maps with the manual mapping of layers 5-6 and 7-8 showed good agreement.

Porosity

Porosity was obtained by petrophysical analysis. Kriging software was used to develop the porosity and water saturation between the wells. This information was input into the simulator.

Porosity and Net Thickness Cut-Off

Work on production decline analysis using type curves for hydraulically fractured wells provided estimated drainage areas which initially overlapped in several wells indicating the need for corrections to the initial cutoffs to the porosity and shalyness. Subsequent corrections of the porosity cutoffs were done. The best estimated corrected values were figured again and these results were input to the simulator. These cut-off modifications changed the initial net thickness, and the final estimates were input into the simulator.

Initial Water Saturation

The water saturation values obtained by the petrophysical analysis were estimated for each layer. Irreducible water saturation from the displacement experiments on relative permeability compared favorably to the petrophysical results. The irreducible water saturation of 0.48 from the core plug experiments was used as initial Sw_{irr} input to the simulator.

Permeability

The permeabilities were estimated from two sources. The permeabilities estimated from the production-fracture type curves compare favorably with the permeability map developed using the correlation derived from log data and the minipermeameter analysis. Three reservoir core samples from the wells Vern Marshall #1, Machi 1 Ross, and Eckhardt #1 of the Hambert Field were described geologically. A permeability depth profile for each core was obtained with the Pressure Decay Profile Permeameter. This permeability profile for the well Vern Marshall #1 was compared at the corrected depth with the porosity log, generating from these two curves a porosity-permeability transform correlation. Individual permeability distributions for the selected layers were prepared from the log transforms. This transform correlation was used to calculate permeability values at the well locations from the porosity logs at the well locations. The average values from each selected layer were obtained. Mapping of the average porosity and generated permeability values using kriging software orienting the depositional trend compared favorably with the hand test maps. These results were imported into the simulator.

Relative Permeability

Relative permeability experiments at lab and reservoir conditions were performed on a core plug of the well Vern Marshall #1. Drainage and imbibition relative permeability curves for oil and water were constructed by modeling and simulating the core flooding experiments. The numerical simulation results were matched with the experimental observed results. These relative permeability curves were used as a starting point in the simulation model.

Relative permeability data obtained from the Terry Sandstone core experimental work were used as a starting point in the simulation model. These curves were obtained from the best of the three cores measured. The measured water relative permeability is very low (approximately 0.1 at Sor). This agrees with field performance where the actual water production is insignificant. Similarly, gas coning is not a problem which may be due to the low vertical permeability and the shale laminae in the sand bodies. Increasing GOR's are not a problem, which supports a slow advance of the free gas in the reservoir.

Gas-Oil Contacts

Due to the compartmentalized nature of this reservoir, several differing gas-oil contacts are in evidence. Refinement of the relative locations was accomplished with runs from the simulation model. To simplify the model without degrading the results, sharp gas-oil contacts with no transition zones were used, and consequently no capillary effects were simulated.

The GOC of the five regions were modified several times throughout the process of history matching. Table G-4 summarizes the final GOC for each of the five regions:

TABLE G-4
GOC Data by Reservoir Simulation Region

REGION	Initial Pressure	GOC (ft)	Bubble Point Pressure (psia)
1	1650	282	1650
2	1650	325	1650
3	1650	325	1650
4	1650	337.5	1650
5	1650	305	1650

Initial Oil, Gas, and Water in Place

Initialization of the simulation model was successfully tested. The oil, gas, and water distribution are summarized in Table G-5. These reservoir simulator generated values are reasonable based on an independent check.

TABLE G-5
Initial Conditions Based on Reservoir Simulation

	Initial In Place Volume			
	Oil MMSTB	Total Gas BCF	Water MMSTB	Free Gas BCF
Region 1	12.0	20.3	31.1	11.9
Region 2	2.7	3.3	5.3	1.3
Region 3	3.2	3.0	5.0	0.7
Region 4	14.3	10.2	18.2	0.2
Region 5	1.7	2.0	3.2	0.8
Total Field	33.9	38.8	62.8	14.9

During the history-match phase, minor changes were made in the initial conditions of gas and oil in place due to minor local changes in thickness. The final values are shown in the following table.

TABLE G-6
Initial Conditions Based on Reservoir Simulation

	Initial In Place Volume			
	Oil MMSTB	Total Gas BCF	Water MMSTB	Free Gas BCF
Region 1	12.8	26.6	33.4	12.8
Region 2	3.8	4.8	5.6	0.6
Region 3	3.7	5.1	6.1	1.1
Region 4	10.7	15.2	18.4	3.7
Region 5	2.0	6.5	3.2	0.6
Total Field	32.9	58.8	66.9	18.8

Well Information

Naming Convention

Wells were named in the simulator based on the last portion of the API number assigned to the well. The API numbers are of the form 05-123-XXXXXX in the study area. The 05 designates Colorado, while 123 designates Weld county. Because all of the focus area wells are in Weld County, Colorado, the XXXXX portion of the number specifies a unique well.

Well Completions

Figure G-5 illustrates the focus area well count. The completion reports of the wells indicate that most of the wells were perforated in layer 4, several of the wells were shot also in layer 3 and some of them in layer 5. For the simulation model it was assumed that through hydraulic fracturing most of the wells were open in layers 3, 4, and 5. Layers 1 and 2 are sparse sand bodies, are thin, and have low porosity. For the simulation model, it was initially assumed that neither layer 1 nor layer 2 were open to production. Through the history matching process it was found necessary in some wells to close layer 3, in others to close layer 5, and in some to open layer 2.

Gathering Centers for the Simulation Model

The reservoir simulator incorporates nine gathering centers. Seven of the gathering centers have two wells each. One center has three wells, and one center has seven wells.

Production History

Production history from Dwights Energy was imported into MS Excel for data checks and allocation of production. The Dwights data covered from the field start date until October 1993. Approximately 53 wells were found to be producing from the Terry. Unfortunately, many of the wells were producing into gathering centers, and production was reported on a lease basis, rather than the individual well production. The simulator needs production allocated on an individual well basis for best results. In one case, seven wells were producing into one gathering center. These wells were producing from three fault blocks, each fault block having different rock properties and fluid contacts.

Where individual well production was not known, the available production data was allocated by noting the date at which a well was completed and the subsequent incremental rise in production. The incremental rise was attributed to the new well. Either straight line or hyperbolic decline was used to project production from the previous well. Figure G-6 illustrates this procedure. Occasionally, more than one well would come

on line at the same time. In these cases, the IP reported on the scout tickets was used to, proportioned the incremental rise to each well, and then a declining production was used to forecast the individual well contribution. For each lease, the summation of the allocated individual production is consistent with the total lease production.

A similar problem occurred when production was updated from October 1993 to the latest available from the Colorado Oil and Gas Commission (December 1995). Over 40 new Terry completions were in the study area. Most of these wells had production which was commingled with that of lower zones. The production was allocated similarly to the procedure described in the above paragraph.

The simulator also needed to know whether a particular well was primarily a gas well or an oil well. When making a history match run, the simulator uses the primary phase, gas or oil, as its basis of production. It attempts to produce the primary phase volume, and lets the physics dictated by the mathematical model determine the corresponding volume of the secondary flow stream. The primary phase was determined by choosing which reservoir volume of the produced phases had the greater volume.

History Match Runs

Introduction

The history matching phase of this effort consisted of making reservoir simulation runs over the period of historical production, 1973 to the end of 1995. The goal of these runs was to adjust the reservoir and fluid properties until the simulated production, gas and oil, was essentially identical to the actual production. Normally, history matching consists of two distinct phases, 1) matching pressure data and 2) matching fluid saturations. Unfortunately, pressure data was not widely available. The initial reservoir pressure was determined from a few well tests which were performed early in the life of the field, Appendix F. Because of the lack of subsequent pressure information, the history matching effort concentrated on matching reservoir fluid distributions.

Model Adjustment

The history match adjustments were made in several phases. The changes were made on a region scale first, on a sub-region scale next, and finally on an individual well basis. The first change was the fine tuning of the gas-oil contacts. These were adjusted to make the greatest number of wells in a given region match production. The gas regions have a gas-oil contacts lower than those of the oil regions. Changing the gas-oil contacts had a great effect on the production flow streams.

Properties on a sub-region scale were adjusted next. When wells in close proximity had similar characteristics, an attempt was made to group them together and adjust reservoir properties as a group. The simulator allowed creating additional PVT, rel perm, and fluid regions. Additionally, each cell's or group of cell's porosity, permeability, and thicknesses were modified.

The next history matching phase was to adjust the individual wells and localized regions around the wells to obtain better agreement between the actual production and the simulated production. The items adjusted were the following:

1. Fault locations.
2. Formation thickness.
3. Formation porosity.
4. Relative permeability.
5. Perforation location.
6. Permeability-thickness product in well equations.

Two types of conditions caused the simulated rates not to match the historical rates. There may not have been enough fluid to produce the specified volumes or the wrong types of fluids were produced. The first condition was corrected by increasing the available volume (items 1, 2, and 3), while the second condition was corrected by changing the fluids ability to flow (items 4, 5, and 6).

Water production was insignificant and was ignored. Also, oil production from gas wells with GOR's exceeding 75,000 was insignificant and ignored. At these high GOR's, the oil produced was most likely a condensate and was not modeled.

Final History Match

When the simulated production history was judged to be close enough to the actual production history, the history matching process was complete. Figure G-7 illustrates the field wide agreement between the historical and simulated production. Figure G-8 is an example of an individual well's performance and history match.

Additional pressure data and more precise allocation of well production would have improved the history matching process.

Prediction Runs

Prediction runs were made to forecast production from the end of the history match, January 1, 1995 until the year 2025. The production rates coupled with the time value of money determined that running the simulation longer than that time would not be of value.

To change over from the history match mode to the prediction runs, each well's producing bottom-hole pressure was set at 150 psia. Production constraints were added to the simulator for economic limit cutoffs. Gas wells needed to produce at least 10 MSCF/D, while oil wells needed to produce 1 BOPD as a minimum.

Numerous cases were investigated using the full field mode. These cases are summarized in the Economic Analysis Report, Appendix H.

Fig. G-1 Study Area.

Fig. G-2 Simulation grid.

Fig. G-3 Regions in study area.

[illegible]

Hambert Study Area

Fig. G-5 Well count.

Fig. G-6 Production allocation.

Fig. G-7 Field history match.

Fig. G-8 Example well history match.

APPENDIX H

Management Strategies and Economic Analysis

by

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Introduction

The Hambert-Aristocrat Field in the Denver Julesburg Basin in Colorado was selected to test the methods of integration. A specific goal was to determine how a multidisciplinary approach could be used to improve the reservoir description and reserve estimates. This economic analysis takes the improved description and tests possible future actions for the Hambert-Aristocrat study area. Through this process, the positive economic effects of integration on field management is quantitatively evaluated. Also, an analysis of the economic impact of improved reserve estimates, and an analysis of the value of purchasing imperfect information was conducted.

Approximately 100 wells within the study region were evaluated using historical production data and simulation projection data. Historical production data was obtained through the operators, Dwight's Energy, and the Colorado Oil and Gas Commission records. Annual net cash flows and mid-year discounting were used to calculate the Net Present Value discounted at ten percent.

Economic Analysis

Management strategies, an analysis of the incremental benefits of improved reserve estimates, and an analysis of the value of imperfect information are presented in the following sections.

Management Strategies

The strategies investigated fall into two categories: first, strategies that could be implemented as of the effective date of our projections (1/1/95); second, strategies that assume that the field could be developed again, but this time using a different development scheme. The first group of strategies will be referred to as the Current Strategies while the second group of strategies will be referred to as the Time Zero Strategies. All strategies assume that the sole production target is the Terry Formation. Production from other formations was not included in the analysis. Producing from multiple zones is common practice in the area.

Economic Assumptions

Two major assumptions were made for the economic analysis in order to bring all wells to a common comparison point. While there may be some error generated by these assumptions, the possible error created is not great enough to skew the results.

1. All wells have equal costs of drilling, completion, etc.
2. The simulator production data is a realistic predictor of future outcomes and provides the best estimate of the ultimate recoveries.

Twelve companies operating in the study region were contacted to obtain drilling, completion, and production costs. Oil and gas prices, production tax rates and net revenue interest rates were assumed to remain constant over the life of a well. The following assumptions were made. All calculations were made before income taxes.

1. Drilling and completion costs: \$200,000/well
2. Production costs: \$4,800 per year/well
3. Severance and Advalorem Taxes: 13 % of revenue
4. Net Revenue Interest: 87.5 %
5. Gas Price: \$1.20 per Mcf
6. Oil Price: \$18 per Bbl

Current Strategies

For the Current Strategies, baseline economics were established using the reservoir simulator to estimate the future production from January 1, 1995 (1/1/95) to an economic limit flow rate. Cash flow projections, starting with 1/1/95, were made for each of the cases investigated. These cash flow projections were compared to the baseline case to estimate the incremental benefit of the strategy. The following Current Strategies were investigated.

1. Perforate layer one in the Terry, Fig. 1.
2. Perforate layer two in the Terry, Fig. 1.
3. Initiate an infill drilling program which has no spacing limitations. The locations of additional wells were selected by an integrated effort taking into account the performance of existing wells.
4. Hydraulic fracture or re-fracture existing wells. Candidate wells were chosen through an integrated effort.
5. Optimum current strategy. Combine the best of cases 1-4.

Time Zero Strategies

1. Perfect knowledge. Only drill and complete wells with positive NPV₁₀'s. This scenario assumes an ability to change the initial development decisions (Time Zero), and establishes an upper bound when the benefits of improved well selection are being evaluated. All wells were assumed to be completed at a common starting point.

2. Horizontal drilling. Determine potential economic benefit of horizontal wells. If costs are a barrier, estimate the costs at which horizontal drilling would be a viable strategy.

Results of Management Strategies

There are some management strategies that were investigated or considered but were not listed. Water injection and gas injection, for example, were tested in the simulator but the options were quickly eliminated based on poor fluid injectivity and production performance. Table 1 presents a summary of the economics for the various cases. The follow paragraphs capture the salient points for each strategy.

TABLE 1

Summary of Management Strategies
Incremental NPV₁₀

Current Strategies	NPV ₁₀
Perforate Layer One	Negative Incremental NPV
Perforate Layer Two,	\$ 60,000
Infill Drilling	\$ 170,000
Re-Fracture	\$ 360,000
Perforate Layer 2 + Re-Frac Wells.	\$ 420,000
Time Zero Strategies	NPV ₁₀
Common Starting Point	\$ 13,700,000
Horizontal Wells	\$ 700,000

Current baseline economics were based on the wells that were producing at an economic rate on the effective date of the analysis, 1/1/95. The baseline NPV₁₀ for the Current Strategies is \$8.8 million. This is based on producing 18,909 MMSCF of gas and 463 MSTB of oil starting on 1/1/95. The cumulative production for the study area from Time Zero to 1/1/95 was 20,345 MMSCF and 928 MSTB of gas and oil, respectively. The EUR was projected to be 39,245 MMSCF and 1,391 MSTB.

1. Perforate layer one in the Terry. No wells generated a positive incremental NPV₁₀ when completed in layer one. Therefore, this strategy was not considered economically viable as an overall field option. This economic projection is based on log derived values for hydrocarbon volume that were input into the reservoir simulator, and an assumed recompletion cost of \$50,000 per well. It is possible that the input to the simulator understates the true potential. However, based on our current estimates, perforating layer one does not add an incremental NPV₁₀.

2. Perforate layer two in the Terry. This strategy generated a positive incremental NPV₁₀ of approximately \$60,000 among three wells. Therefore, this strategy is considered to be viable, but very risky as an overall field option. As with strategy one, this economic projection is based on log derived values for hydrocarbon volume that were input into the reservoir simulator, and an assumed recompletion cost of \$50,000 per well. The three wells with positive incremental gains are located in the buffer region of the reservoir simulator which adds to the uncertainty. It is possible that the input to the simulator overstates the true potential. However, based on our current estimates, perforating layer two does add an incremental NPV₁₀. Figure 2 shows the location of the wells having a positive incremental NPV₁₀.
3. Infill drilling. This strategy is not considered economically viable. One well had a marginal positive incremental NPV₁₀ given the riskiness of the location. The prospect is near a possible fault where the reservoir quality is poor, Fig 3.
4. Fracture or re-fracture wells. Three candidate wells were identified for possible re-fracture treatment. The economics are based on reservoir simulation results that assumed a 100% increase in the PI for each well. The cost for each re-fracture treatment was assumed to be \$33,000. The wells are all located in the buffer region for the reservoir simulation, which adds uncertainty, Fig. 4. The combined incremental NPV₁₀ for these wells is 360,000. Other fracture treatment variables should be considered before making a final decision.
5. Optimum Current Strategy, perforate layer two and re-fracture. The combined NPV₁₀ for this strategy is \$420,000.

The following is a summary of the Time Zero Strategies.

1. All wells initiated at a common start point. All wells having a positive NPV₁₀ were completed at a common starting point. This approach sets an upper boundary on the value of integration related to optimal well selection. Dry holes and marginal completions were eliminated. This case was compared to the Time Zero baseline economics which used the reservoir simulator to estimate the production. When assessing the incremental value of improved well selection, the incremental gain should not exceed \$13.7 million under these assumptions.
2. Horizontal well analysis. The use of horizontal wells to increase the communication with the reservoir and to reduce the number of wells was investigated. Figure 5 shows the location of the three horizontal wells. An assumed drilling and completion cost of \$500,000 was assigned to each horizontal well. If these three horizontal wells had been drilled replacing fifteen vertical wells, a positive incremental NPV₁₀ of approximately \$700,000 would have been generated. The actual operations, however, would have carried considerable risk. Horizontal wells have not been drilled in this area and therefore the cost assumptions cannot be confirmed. Several operators and service companies were contacted for price estimates and provided estimates from \$100,000 to \$1,000,000. Also, an accurate reservoir description would be essential to the success of these wells. In our opinion, an adequate reservoir

description would not be available at the time the drilling decision is made. A possible alternative would be an improved seismic interpretation.

Benefits of Improved Reserve Estimates

One project goal was to improve reserve estimates through integration. The initial reserve estimates were based on volumetric data, and considered the best initial estimate for net pay (Appendix C). These initial estimates did not include the benefit of an iterative process and form the basis for the reserve estimates without integration.

These initial estimates were later revised during the iterative process of integration. The refinements in net pay were made using the integrated results of the core description, minipermeability measurements, production performance, and log derived values (Appendix C). Another round of revisions was made during the history match phase of the reservoir simulation (Appendix G). These revisions in hydrocarbon thickness form the basis for quantifying the value of integration.

The economic benefit of integration is quantified by comparing the changes in hydrocarbon thickness, and therefore ultimate recovery and net present value, from the initial estimate to the integrated estimate, and finally to the history matched value used in the reservoir simulator. The EUR comparisons for each region of the reservoir are captured in Figs. 6 and 7 for oil and gas respectively. The comparison of a cumulative hydrocarbon thickness for each region is captured in Fig. 8. Finally, a comparison of the Net Present Value discounted at 10% for the study area is made in Fig. 9.

The comparisons show that the initial reserve estimates were low. The comparisons also show the reserve estimates with the integration were consistently higher than the final reserve estimate based on reservoir simulation. The overstating of the reserves may be in part due to the approach used. The bulk volume water - bulk volume flushed zone difference was the recommended method of estimating net pay (Appendix C). However, in this study, cutoff values for S_w , porosity, and shale volume that mimic the BVW-BVXO method were used to estimate net pay. This was done because of the inconsistency in the quality of the hard copies that the digitizing was based on. Digitized data should be obtained directly from the service company when the logs are run. In the example presented in Appendix C, tuning cutoffs to mimic the BVW-BVXO over stated the hydrocarbon thickness when compared to the BVW-BVXO derived net pay. In retrospect, over estimating hydrocarbon thickness is representative of the outcome for other wells. This adds additional support for the BVW-BVXO method to discriminate pay in the study area (Appendix C).

Reducing the uncertainty in the reserve estimates is one possible objective of integrating data and people. In the Hambert-Aristocrat study, the iterative process utilizing an integrated team came much closer to estimating the final value derived from the reservoir simulator. The value of reducing the uncertainty in the reserve estimates was quantified through an incremental NPV₁₀ analysis. The incremental value was estimated by comparing the NPV₁₀ of the net operating incomes for the final reserve value with the NPV₁₀ of the estimated net operating incomes from

the initial reserve estimate. In the Hambert-Aristocrat study area, the incremental NPV₁₀ is approximately \$14 million. The estimated cost of integration, \$1 million, has been accounted for in this estimate. The costs assume the production for a twenty-four month period. The cost for people and data for the integration of the core, minipermeability measurements, log analysis, and production data were also included.

A summary of Net Present Values discounted at ten percent (NPV₁₀), Estimated Ultimate Recovery (EUR), Estimated Remaining Reserves (ERR), cumulative production, and oil and gas recovery efficiencies calculated from final simulation data for the study area wells are presented in Table 2.

TABLE 2

Summary of Estimated Ultimate Recovery (EUR), Estimated Remaining Reserve (ERR), Cumulative Production, and Oil and Gas Recovery Efficiencies on 1/1/95 for the Study Area Wells

The NPV₁₀ is for ERR on 1/1/95

REGION	EUR GAS (MMSCF) / OIL (MSTB)	ERR GAS (MMSCF) / OIL (MSTB)	Cumulative Production (MMSCF /MSTB)	GAS Recovery Efficiency	OIL Recovery Efficiency	NPV ₁₀ ERR
1	17484/93	7858/12	9626/81	65.7%	0.7%	\$ 2,308,288
2	4335/520	2260/97	2075/423	91.2%	13.6%	\$ 1,536,734
3	4882/263	2351/54	2531/209	96.1%	7.2%	\$ 1,231,038
4	11797/474	5729/204	6068/210	77.7%	3.9%	\$ 3,090,818
5	756/101	711/96	45/5	11.5%	5.0%	\$ 651,118
TOTAL STUDY AREA	39254/1391	18909/463	20345/928	67.5%	4.2%	\$ 8,817,996

Value of Imperfect Information

Operators have the opportunity to acquire many types of information; usually with the purpose of improving profits by clarifying uncertainty. Several questions need to be addressed to answer this question. However, a balance needs to be achieved between the cost of the information and the benefits derived from improved decision making. How much can we afford to pay to reduce uncertainty? When do the costs exceed the expected benefits? A method referred to as bayesian analysis can be used to help answer these questions. The method was applied to the analysis of purchasing 3D seismic to resolve the uncertainty in reservoir quality and thus well selection (drill or don't drill). It is important to note that the seismic for the Hambert-Aristocrat area was not run with this objective (Appendix B). Current 3D seismic technology may have provided different conclusions from the analysis included in the following section. This issue is addressed in Appendix B. The following case study provides an example of the methodology used to analyze the purchase of information to resolve uncertainty.

Case Study

Seismic survey data was available for the northern portion of the study area. For this analysis, it is assumed that the operator has three options:

1. Do not purchase seismic data and drill sixteen wells;
2. Purchase seismic data and avoid drilling in areas which the seismic data has determined to have poor potential (negative NPV₁₀). The areas in which the seismic data has been determined to have good potential (positive NPV₁₀) would be drilled, or
3. Don't drill.

As an historical reference, the first option was chosen. Sixteen wells were drilled resulting in six positive NPV₁₀ wells and ten negative NPV₁₀ wells. Seismic data was later procured after drilling was completed within the area. The historical well performance and seismic interpretation provide the basis for quantification of the value of improved well selection from seismic data. The areas interpreted from the seismic data as either poor or good potential, based on the NPV₁₀, are shown on Fig. 10.

In our hypothetical case, the operator would like to determine if a seismic data purchase is cost effective. The operator is interested in knowing if the purchase cost of seismic results in a greater expected NPV₁₀ than could be expected without the benefit of the seismic interpretation. The operator analyzes his leases and determines there are sixteen locations where there is sufficient positive potential to drill. He then estimates the seismic survey cost to equal \$10,000. The operator then uses analogous relationships with adjacent fields / reservoirs and determines the following estimates. These estimates are based on the historical data in the study area.

1. The average dry-hole cost for this area is \$170,000;
2. The average producing well NPV₁₀ is \$270,000;
3. The historical seismic prediction accuracy in predicting the performance in areas identified as poor is 100% in this reservoir. In other words, if the seismic data predicts a negative NPV₁₀ region, the probability is 100% of drilling a negative NPV₁₀ well.
4. The historical seismic prediction accuracy in predicting the performance in areas identified as good is 46%. In other words, 46% of the wells in an area identified as good have a positive NPV₁₀;
5. The historical success rate in this area is 37.5%. Given this success rate, the operator expects to drill six producing wells and ten dry-holes on his lease with the current information.

Using these estimates, the operator constructs an analysis to compare the expected values for each of the decision alternatives. The decision tree for these alternatives is presented as Fig. 11.

Realize, at this point, the operator has made two assumptions in which he must have confidence: the accuracy of the seismic data and interpretation of that data; and the probable number of producing wells and dry-holes among his leases. Therefore, in purchasing the survey, he is relying on the seismic interpretation to identify whether his leases are in a positive NPV₁₀ region or negative NPV₁₀ region. The operator will attempt to avoid dry-hole costs by not drilling in the identified "poor potential" areas. One of the risks the operator is taking is in not developing producing wells in an area identified as "poor" based on the seismic interpretation.

The expected value of the decision to drill without the seismic data is a negative \$91,000. The expected value of the decision to purchase the seismic data is \$326,880 and assumes a survey cost of \$10,000. The expected value of the decision to not drill is zero. Under these assumptions, the decision with the largest expected value is to purchase the seismic.

Results

Bayesian analysis concluded that it would have been economically feasible to purchase seismic data in order to avoid dry hole costs. The reliability was sufficient to warrant the expenditure to resolve the uncertainty in well selection.

It should also be noted that the data did provide other important information. The survey data confirmed the existence of a major northeast to southwest running fault in the study area. Had no seismic data been present, this major fault may have been missed. Not acknowledging this fault could have had dramatic effects on secondary recovery operations although not in this area, since secondary recovery is not a viable option. Also, one of the two marginal or dry holes drilled near or in the fault complex could have been avoided. One of the dry holes is assumed to be necessary to learn about the reduction of porosity that occurs in the faulted region (Appendix B, C).

A number of seismic data acquisition and processing techniques have advanced since early 1982 when this data was acquired and processed by Amoco Production Company. Modern acquisition geometries would improve the offset, azimuth, and fold distribution of the seismic data. Detailed reprocessing of the seismic data would allow processing parameters to be fine tuned for the Terry Formation reservoir. Processing techniques used for S-waves have changed significantly since these data were processed. These improvements in acquisition and processing would result in greater resolution within the current zone of interest, resulting in a more accurate and detailed seismic interpretation (Appendix B). This improved interpretation could increase the performance of the positive region prediction accuracy.

Conclusions

The economic benefits of integration were quantified:

- a. Integration reduced the uncertainty in estimating net pay and estimates of ultimate recovery. The incremental benefit of reducing the uncertainty in reserves has an estimated value of \$14 million in the study area.
- b. Implementing the Current Strategies in the study area has the potential to add a NPV₁₀ of approximately \$400,000. Risk has not been taken into account in making this estimate.
- c. Horizontal wells may be a viable development alternative for similar reservoirs in the future. An accurate reservoir description would be essential to the success of these wells. Detection of compartments at the time the drilling decision is made would be needed.

SPOT LOCATION
1980FNL 1980 FEL 29 4N 65W

CSM/DOE ~ Terry
Preliminary Work Product
Contract No. DE-AC22-93BC14891
Task 1.1.2

OPERATOR : Champin Petroleum Corp
WELL NO. : 1 Gohlender 32-39 { 4
COUNTY : Weld
STATE : Colorado
DEPTHS : 4450.0 - 4850.0
Date Logged : 8/11/78
APL Number : 09553
AKB : 4888.0
PROCESS DATE : 07/27/1995 / 14:10:00

[illegible]

Fig. 1 Log analysis summary plate showing the five layers used in the reservoir simulator.

Fig. 2 Location of wells with positive incremental benefit from perforating layer two.

Fig. 3 Location of potential infill well.

Fig. 4 Location of potential re-frac wells.

Fig. 5 Location of three horizontal wells simulated to replace fifteen vertical wells.

ESTIMATED ULTIMATE RECOVERY - OIL

Fig. 6 Comparison of initial and integrated estimates for oil EUR (bbls) with final best estimate from simulator.

ESTIMATED ULTIMATE RECOVERY - GAS

Fig. 7 Comparison of initial and integrated estimates for gas EUR (Mcf) with final best estimate from simulator.

HCFT - PREDICTIONS

Fig. 8 Comparison of initial and integrated estimates for hydrocarbon thickness with final best estimate from simulator.

NPV₁₀ PREDICTIONS

Fig. 9 Comparison of initial and integrated estimates for $\bar{NPV}_{10}$ with final best estimate from simulator.

Fig. 10 Well selection areas based on integration of seismic, production, petrophysics, and core.

Fig. 11 Decision tree for the purchase of seismic data.