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Net Pay Estimates Utilizing the Jensen-Menke Statistical Cut-off Calculation: A Case Study of Glauconitic Sandstone in the Blackfoot Field, Southern Alberta

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ABSTRACT

Cut-offs are required to exclude the reservoir portion that does not contribute significantly to evaluating hydrocarbon in situ or reserve estimation. There is no universally accepted set of definitions, but it is necessary to have a firm grasp on the fundamental terms and expressions used in volumetric analysis employing core, well-log data.

Oil and gas are trapped in the Blackfoot Field's multiple fluvial and valley-fill reservoirs of the Glauconitic sandstone. Two wells, A-08-023-23W4 and B-08-023-23W4, were chosen to quantify parameters needed to estimate net pay thickness (NPT) and net-to-gross ratio from the cores data in both wells.

Understanding charts, which show how average parameters change with a cut-off value, are used to determine the final cut-off. Using the statistical criterion for the assessed wells, an appropriate porosity limit for the net-to-gross ratio (NTG) estimate is being sought. A perspective on choosing porosity cut-off values from a statistical and core data perspective is provided.

The cores used in this investigation were analyzed for permeability and porosity under controlled laboratory settings. It is possible to make inaccurate predictions when using least-squares regression to determine porosity (or permeability) cut-off values. Using a

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probabilistic method, Jensen and Menke assessed the precision and inaccuracy of various porosity cut-off values.
To accomplish this, the line indicating the porosity cut-off values (Øc) was fine-tuned to minimize error and produce the most precise estimate possible. In this case study, we apply the tasks of estimating different porosity cut-off values to identify NPT and NTG and reduce the errors.
A-8-23-23W4's Øc is 0.3 porosity unit (pu) off the best estimate $Ø_{BE}$ values when using the least squares regression line fitted to the porosity and permeability, and the regression line cut-off errors are 2.7% higher. $Ø_{BE}$ matches the least squares regression's NPT cut-off values for well B-8-23-23W4.
The least regression line has a lower error rate than the best estimate for NTG, which is a 2.1 pu difference. According to the results, the NTG for well A-8-23-23W4 and well B-8-23-23W4 are predicted to be 0.9 and 0.8, respectively.
The application of the Jensen and Menke statistical cut-off is contingent upon the reservoir type, and the optimal statistical method for assessing net pay should be combined with all relevant data and analyzed by geologists and engineers.

Key Words: Glauconitic sandstone, core data, Porosity cut-off, least square regression, Net pay thickness.

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تقدير السمك المساهم في الإنتاج بإستخدام طريقه جنسن . منك الآحصائيه في حساب القيمة الفاصلة: دراسة تطبيقيه عن الحجر الرملي الجلايكونيت في حقل بلاكفوت، البرتا، كندا

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الملخص

معرفة القيمة الفاصلة لتحديد السمك المساهم في إنتاج النفط من السمك الكلي للحوض النفطي مهم جدا لتقدير الكمية الموجودة ومقدار ما يمكن إخراجه من المكامن النفطية. يستخدم لهذا الغرض الكثير من الطرق، ونناقش هنا بعض الطرق الإحصائية التقليدية ومقارنتها مع طريقة جنسن ومنك من المعلومات الجيولوجية من اللب الصخري والخواص البتروفيزيائيه.

لهذا الغرض فإن الدراسة تهدف لتقدير القيمة الفاصلة حيث تم إجراء البحث في حقل بلاك فوت بكندا، والذي يحوي حوض رسوبي متكون فيه حجر رملي وطيني، وقد تم استخلاص المعلومات من البئرين A-08-023-14W5 والبئر B-08-023-14W5.

استخدام الطرق الإحصائية الاعتيادية للحصول على متوسط المعلومات وتطبيق خط الانحدار لإحداثيات التقاطع بين المسامية (الفجوات) والسماحية (انتقال السوائل)، ومقارنة النتائج بإستخدام الطرق الإحصائية بطريقة جنسن ومنك على نفس المعلومات. وقد كانت النتائج في حساب متوسط القيمة الفاصلة بإستخدام الطرق التقليدية للبئرين للقيم الفاصلة للمسامية A وB هو 9.7 وحده و12.4 وحده وبمعدلي خطأ قدره 8.3 و7.5على التوالي. بينما بإستخدام طريقة جنسن ومنك الإحصائية فهي 9.4 وحده للبئر

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A و14.5 وحده للبئر B، بينما معدل الخطأ للاحتمالين هو 5.6 و10 للبئرين A وB على التوالي.

هذا التقدير بالطريقة الاعتيادية نتج عنه حساب السمك المساهم في الإنتاج وهو 6.43 متر من السمك الكلي 7.13 متر، وهو نفس القيمة وبالتالي حساب السمك بإستخدام طريقة جنسن ومنك في البئر A. بينما في البئر B كان السمك المساهم باستخدام الطريقة التقليدية هو نفس السمك الكلي وهو 4.62 متر، بينما بإستخدام طريقة جنسن ومنك كان السمك المساهم 3.71 متر من السمك الكلي 4.62 متر. وكانت نسبة السمك المساهم للسمك الكلي بإستخدام الطريقة الاعتيادية وطريقة جنسن ومنك للبئر A هي 0.9 و0.9 على التوالي. بينما بإستخدام جنسن ومنك كانت النسبة للبئر B هي 0.8 بينما للبئر B بإستخدام الطريقة التقليدية هي 1 (أي القيمة الفاصلة كانت تنطبق على كل اللب الصخري).

الخلاصة انه بإستخدام طريقة جنسن ومنك قد تكن جيده لحساب القيمة الفاصلة وتقدير السمك المساهم في الإنتاج للأحواض النفطية المختلفة الخصائص في الطبقات الجيولوجية وتركيباتها، كما إنها طريقه إحصائية مثلى بتقليل الأخطاء في تقييم القيمة الفاصلة، وايضا يمكن استخدامها في إحصاء قيم بتروفيزيائيه أخرى مثل قيم تشبع الماء وحجم الطين، لكنها أيضا طريقه لديها بعض العيوب فهي لا تصلح لتقييم القيمة الفاصلة في حال وجود معلومات قليله كما في هذه الدراسة، كما إنها طريقه معقده حسابيا، كما إنها لا تأخذ في الحسبان خواص النفط والغاز في المكامن مثل خواص السوائل الموجودة. ولهذا فإن اختيار الطريقة المثلى لحساب القيمة الفاصلة لتحديد السمك المنتج عموما يجب أن يكون بالمشاركة بين الفريق الجيولوجية والهندسية لتقييم القيمة الفاصلة الفاعلة.

الكلمات المفتاحية: القيمة الفاصلة، نسبة السمك المساهم للسمك الكلي، الحجر الرملي الطيني، خصائص اللب الصخري، الطرق الإحصائية.

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1. INTRODUCTION

Oil and gas are trapped in the Blackfoot Field's multiple fluvial and valley-fill reservoirs of the Glauconitic sandstone, also represented by a regionally wide shoreline sandstone complex that presents through northern and central Alberta. The Lower Cretaceous Fluvio-estuarine Glauconitic channel sands are perhaps one of the most productive oil and gas reserves in Southern Alberta.

Cut-off values are required to ensure the reliability of the approach used to calculate effective reservoir thickness and related reserves. The cut-off is a threshold value used to differentiate pay parts from non-pay sections within each formation. Cut-offs are selected using sensitivity plots that illustrate how averaged parameters fluctuate with a cut-off value.

Net and gross compensation have been studied for decades (Pirson, 1958; Calhoun, 1960; Cobb & Marek, 1998; Menke, 2002; Worthington & Cosentino, 2005; Jensen & Menke, 2006). There is little public information on Net/Gross calculation methodologies because there is no uniform rule and, in most cases, the choice of cut-off is empirical.

The author aims to explore the formation of the net pay cut-off utilizing porosity and permeability, as well as the delineation of net pay and discusses different topics relevant to the calculation of reserves and net pay over the core intervals within glauconitic sandstone formation in the studied field by using statistical conventional least-square regression lines and Jensen and Menke method.

The author seeks to investigate the formation of the net pay cut-off using porosity and permeability, as well as the delineation of net pay and discusses various topics pertinent to the calculation of reserves and net pay over the core intervals within the glauconitic sandstone formation by using statistical least-square regression lines and the Jensen and Menke methods.

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1.1 Geology of the Area

The Mannville Group and equivalent strata comprise the oldest Cretaceous rocks over most of the Western Canadian Sedimentary Basin. The Mannville Group underlies the Colorado group (Joli Fou Formation) separated by disconformities, and it overlies the post-Paleozoic unconformity at the time of deposition of the underlying Ostracod beds Figure 1.

The Mannville Group's complicated stratigraphy and palaeography may be separated into Lower and Upper Mannville units. The Lower Mannville units are primarily composed of non-marine clastic. The northward transgression of the Lower Cretaceous Sea resulted in the deposition of Upper Mannville strata that gradually on-lapped southward.

The Mannville Group locally consists of three incised valley fills of differing compositions. The Upper Glauconitic Formation of the Lower Mannville Group trapped and produces oil and gas in the Blackfoot field within quartzose sandstone in the incised valley or channels of the glauconitic member in the Blackfoot area (Dufour et al., 1999).

The Glauconitic member of southern Alberta is an unconformity-bounded sequence that evolved on an ancient coastal plain because of relative sea level fluctuation (Wood, 1992). In the eastern portion of Alberta, the Glauconitic sandstone is composed of extremely fine to medium-grained quartz sandstone, whereas in the western part, quartz sandstone is composed of somewhat coarser lithic or sub-lithic sandstone (Potter et al., 1996).

The thickness of Glauconitic sandstone varies between 5 (inter-valley deposits) and 35 meters (valley-fill deposits). In southern Alberta, it is conformably overlain by Mannville Group continental deposits, and the Ostracod strata underneath are composed of brackish water shales, argillaceous, fossiliferous limestones, and thin quartz sandstones and siltstones (Layer et al., 1949).

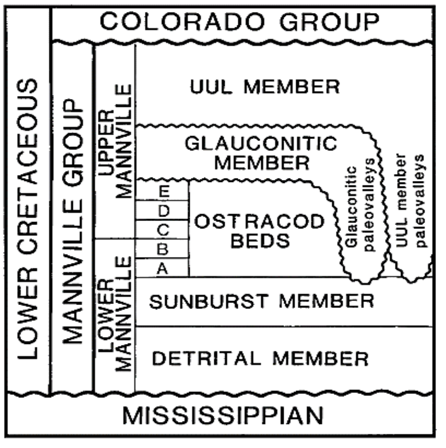

Figure 1. Table of general Stratigraphic Nomenclature for the Mannville Group and equivalent strata in some of WCSB (Arndt., 2017)

1.2 Reservoir Type in the Study Area

The Blackfoot Field is southeast of Calgary Figure 2. This study analyzed two wells, A-08-023-23W4 and B-08-023-23W4, to determine the reservoir's net pay thickness. The upper interval of both wells was used. The top interval is readily identifiable due to the high quality of wire-line log responses; it has a diversity of lithology and rock types. The wells are located within the channel complex that filled part of the incised valley: paleo-drainage was from south to north. At Blackfoot, the Glauconitic compound incised-valley system consists of three distinct incised valleys: the Upper Valley, the Lithic Valley, and the Lower Valley.

The primary reservoirs are the Upper and Lower incised valleys. The lithic incised-valley deposits are not of reservoir quality and act as permeability barriers between the Upper and Lower incised valleys. The interval in question is mostly in the Glauconitic sandstone. The total thickness of Glauconitic sandstone in well A-8-23-23W4 is 34 m (1575-1609 m).

The total thickness of Glauconitic sandstone in well B-8-23-23W4 is 31 m (1655-1686 m).

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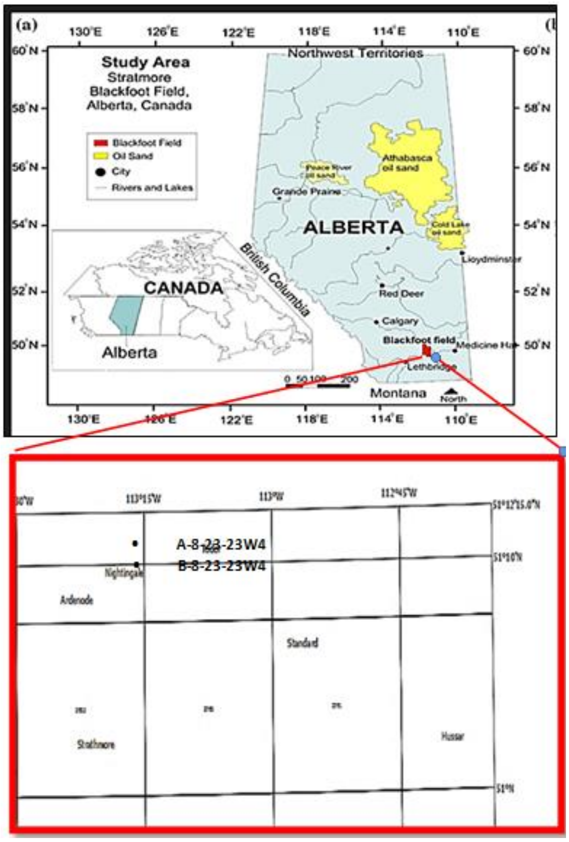

Figure 2: Location map of the studied wells in Blackfoot field, southern Alberta

2. METHODOLOGY AND PROCEDURE

In any reservoir, cut-offs are required to exclude the portion that does not contribute significantly to the evaluation of hydrocarbon in situ or reserve estimation. The reservoir's porosity, permeability, and hydrocarbon saturation must be determined using data from the rocks that define its character (Worthington & Cosentino, 2005).

A review of petroleum engineering textbooks and technical literature demonstrates the contrast between the productive and

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unproductive regions of a petroleum reservoir. Net pay has been a point of desirable area of interest for many years. Numerous ways of measuring cut-offs have been developed, but no one method has emerged as the authoritative foundation for distinguishing net pay. While there is no universally accepted set of definitions, it is critical to understand the essential descriptive phrases that are frequently used in volumetric analysis using core, well-log data. All the following concepts refer to thicknesses or thickness ratios, and they are interrelated (Worthington and Cosentino, 2005).

The gross reservoir (GRT) interval is made up of all rocks contained within the evaluation interval. *Net sand* (NsT) is made up of rocks that may have reservoir qualities and are composed of clean sedimentary rock. *The net reservoir* (NsR) is made up of net sand intervals with beneficial reservoir parameters. *Net Pay Thickness* (NPT) is the term used to refer to those net-reservoir intervals that contain considerable amounts of hydrocarbons Figure 3.

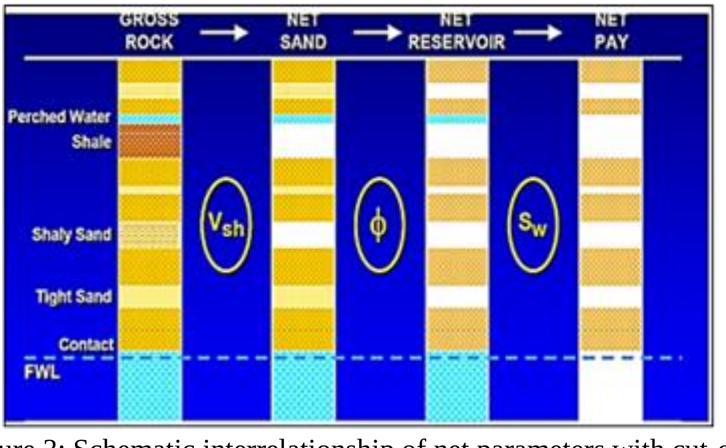

Figure 3: Schematic interrelationship of net parameters with cut-offs applied sequentially (Cuddy, 2017)

The term "Net-To-Gross Ratio" (NTG) incorporates all three of the above definitions. The ratio of net to gross thickness, Net-To-Gross can be stated as Net-To-Gross sand, Net-To-Gross reservoir,

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or Net-To-Gross pay. It is critical to identify the rationale for the net criterion (Worthington and Cosentino, 2005).

2.1 Lithology from Core

Two cores were logged and reported for wells A-8-23-23W4 and B-8-23-23W4. Extremely fine to medium-grained sandstone, interbedded with quartzose sandstone, and occasionally incorporating siderite and carbonaceous makes up most of the Glauconitic sandstone sequence in both cores. Near the base of the interval, which is likewise cemented with bitumen and calcite, there is a mudstone clast conglomerate Figure 4.

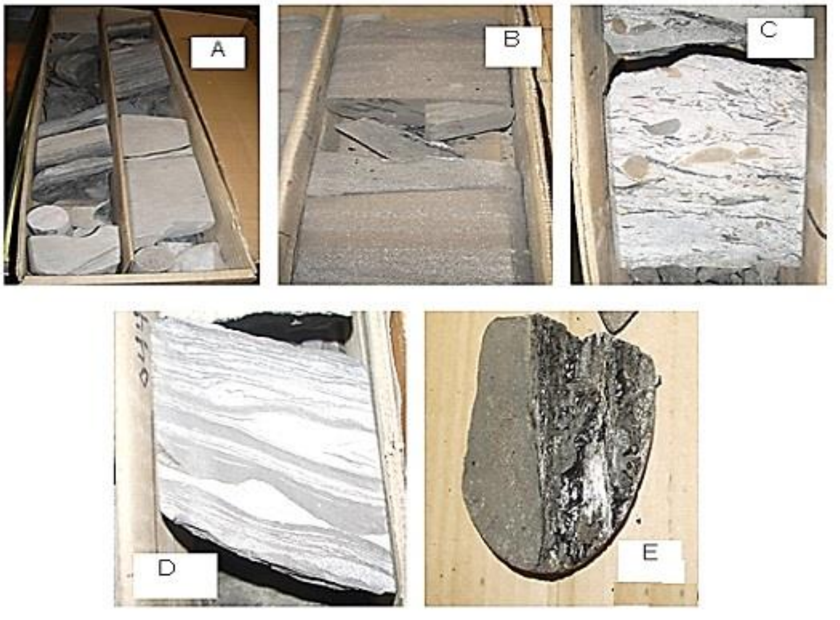

Figure 4: Cores from study wells. **A.** Gray fine-to-lower medium grain size, and low-angle cross-bedded sandstone of well B-8-23-23W4. **B.** Siderite (Brownish color). Siderites are abundant in both cores. **C.** 10 cm piece of upper fine to lower medium sand with mudstone-clasts conglomerate, carbonaceous, chert at the well A-8-23-23W4. **D.** Wavy, low-angle alternative shale, and sand bed, with 2-10 mm in thickness. **E.** Coal clasts of the well B-8-23-23W4

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2.2 Quantified Net Pay

Prior literature related to the selection of net pay based on its intended purpose. Cut-offs should be constructed for a range of specific purposes. As is the case with this study, they should be important to the projected deliverable or their use in calculating reserves. The procedures involved in assessing the field data from the reservoir channel wells.

The core data set represents the permeability and porosity cross-plot. The author does not address the geological, petrophysical, and engineering foundations for the net pay calibration. Statistical concepts can be directly utilized to enhance the understanding of sample data and to quantify the distribution of natural variables and influences within reservoirs.

In this study, we apply the traditional method and compare the results using Jensen & Menke's (2006) statistical method to estimate the porosity cut-off to predict the net pay and net-to-gross ratio over intervals of cores and investigate the results and statistical challenges involved in reducing the error rate associated with estimating net pay.

2.2.1 Traditional Method

The method utilized the minimum regression line fitted to the porosity and permeability data from the cores to determine the cut-off porosity value. Due to the lack of Special Core Analysis in this study, the permeability and porosity were determined under standard conditions, namely absolute gas permeability.

The standard technique, provided an acceptable value for permeability (*K*c) is established, is to estimate porosity cut-off (Øc) by fitting a regression line to a cross plot of porosity and permeability data. The use of the regression line allows one to estimate Øc, locate ranges of net pay, and derive the NTG ratio for a given formation.

2.2.2 Jensen and Menke Method

Jensen and Menke (2006) estimated the accuracy and error of various porosity cut-off values using a probabilistic technique.

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This was performed by adjusting the Øc line to reduce mistakes and provide the most accurate (best) estimate of the porosity cut-off value, denoted by ($Ø_{BE}$)
The technique is based on the definition of four zones in the log *k* – Ø cross plot, with the average permeability (*K*c) and porosity (Øc) threshold values defining the region boundaries. In this study, the author expands on the prior debate and investigates the effect of modifying the Øc line and whether a difference in outcomes is observed compared to the traditional method.
The region (A) denotes a non-pay zone (*k*<*k*c & Ø<Øc) for the data identified with *K*c and Øc. In comparison, region (D) indicates a net pay zone (*k*>*k*c & Ø>Øc) for the data specified with *K*c and Øc. Regions (B) and (C) reflect erroneous misidentifications where (*k*>*k*c & Ø<Øc) or (*k*<*k*c & Ø>Øc) denote an error depending on the quantity of formation rock.
The probability that an event, say A, happens is denoted by prob (A) and may be computed by dividing the number of points in area A by the total number of points depicted in the cross-plot. Thus, the probability of occurrences B, C and D are denoted by the variables prob (B), prob (C), and prob (D). In other words, the probability error is defined as the ratio of the sample points (nx) in (A), (B), (C), or (D) to the total sample points (n), (nx/n).
The most accurate predictions of Øc, denoted by the notation $Ø_{BE}$, resulted from either decreasing the likelihood probability of (B) and (C) or maximizing the probability of (A) and (D). This method, though, is not always the most precise one. The most precise estimate of the NTG can be obtained by selecting Øc such that the probabilities of regions (B) and (C) are the same to minimize the error of mistaking pay or not pay interval, regardless of the magnitudes of the regions.

3. RESULTS AND DISCUSSION

3.1 Core Data

Incorporating core analysis and description with porosity and permeability is one of the procedures for identifying cut-offs and establishing net pay thickness. The porosity and permeability of

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the two core samples were measured and recorded. Figure 5 depicts the porosity and permeability of the core's intervals from wells A-8-23-23W4 (7.13 m) and B-8-23-23W4 (4.62 m).

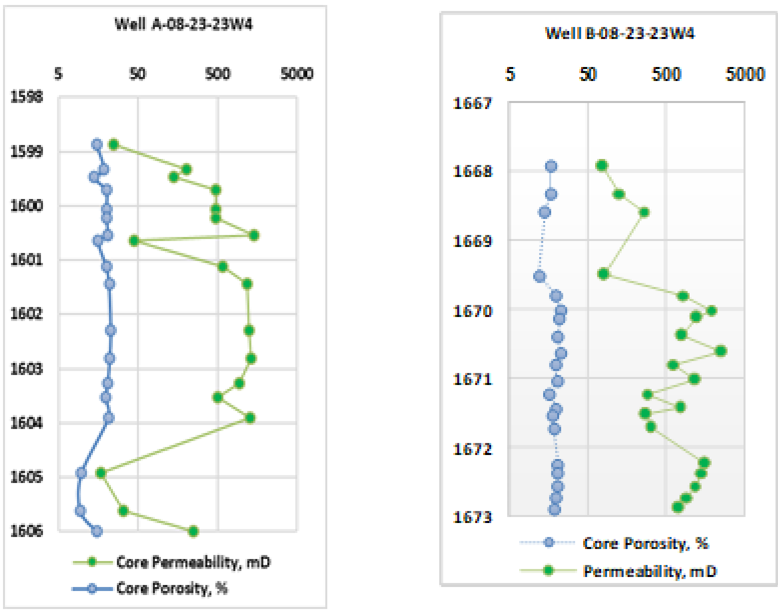

Figure 5: Comparing core-derived porosities and permeabilities for both study wells

3.2 Traditional Method

It is important to note that cut-offs are usually derived empirically from an inspection of data. Once the suitable value for *K*c is determined, however, one common practice is to use a regression line fitted to a cross plot of porosity and permeability data. The appropriate lower limit of permeability and porosity for the whole core interval is computed.

The net pay is estimated using the least square regression line fitted to porosity and permeability data from the cores. The *K*c for the net pay is restricted to the assumption, which is 15.8 mD and 85 mD, where these values correspond to the porosity at the border

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between clean sandstone, shale, and lithic sand in wells A-8-23-23W4 and B-8-23-23W4.
The traditional method for determining Øc is applied to fit a regression line to a cross-plot of porosity and permeability. Using the regression line, we can estimate that the porosity cut-off of the core ($Ø_{CR}$) is 9.7 for well A-8-23-23W4, while Øc is 12.4 for well B-8-23-23W4.
Nonlinear transforms of various sorts are frequently used to convert raw sample data to alter data that is "better behaved." The application of a nonlinear transform, such as the log transform, can be used to overcome a relatively large fluctuation in sample values. The log *K* versus Ø plots in Figure 6 indicate the best-fit line.

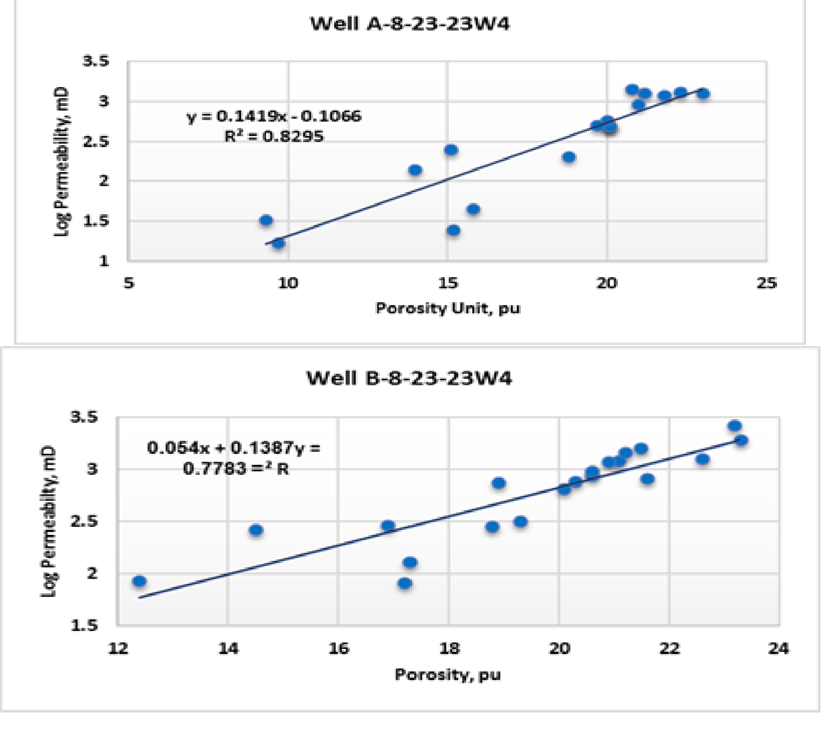

Figure 6: Cross plots of porosity versus log-log-permeability for a glauconitic sandstone reservoir at the core scale

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The linear relationship between log *K* and Ø is excellent in general. The data are evenly distributed on each side of the best-fit line. Correlation coefficients (r) for wells A-8-23-23W4 and B-8-23-23W4 are 0.83 and 0.78, respectively. The large values of (r) imply that the fit is reasonable, and that accurate prediction of permeability values given the values is possible. The Cv is less for ln *K* data, suggesting that there is less difference in the values of the sampled data. The log transform of permeability is ineffective in this scenario because of the small variance in the sample data. A reasonable extension of using summary statistics concepts in this scenario would be to construct a linear relationship between porosity and permeability.

The mean and median values for wells' porosity data are close to one another, indicating a symmetric distribution. In comparison, the median for the permeability data is smaller than the mean, showing that the distribution is positively skewed.

The coefficient variation (Cv) for porosity indicates that variation is modest, but the Cv for permeability indicates that variance is larger for the sample data. Table 1 illustrates the application of a simple summary-statistics analysis to the porosity and permeability data from both wells.

Table 1. Summary Statistics for Studied Wells

Statistics	Variables					
	Well A-8-23-23W4			Well B-8-23-23W4		
	Ø	***k***	***log k***	**Ø**	***k***	***log k***
Mean	18.2	585.9	2.48	19.6	875.8	2.75
Median	20.05	477.00	2.68	20.45	791	2.9
Variance	16.8	25269	0.41	8.7	508108	0.21
CV	0.22	0.86	0.26	0.15	0.81	0.17
SD	4.1	502.7	0.6	2.95	713	0.46
Max	23	1410	3.14	23.3	2650	3.4
Min	9.3	17	1.23	12.4	81.4	1.91

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The most accurate estimation of $Ø_C$ relies on the intended use and application. This approach is poor since it classifies non-pay intervals as pay intervals. This is an optimistic assessment. This may not be the case, as it may result in the perforation of shaly intervals and an increase in the net-to-gross ratio for both investigated wells.

3.2 Jensen and Menke Method

The *K*c for the net pay is calculated to be 15.8 mD for well A-8-23-23W4 and 85 mD for well B-8-23-23W4. It is our goal to determine an estimate for Øc based on the Y-intercept on the regression line of X in this case study. We will also estimate the best $Ø_{BE}$ and compute the error rate using other Øc values and then the net-to-gross ratio for both wells.

Wells A-8-23-23W4's entire areas C and B probabilities have a formation rock estimation risk of error 0.083 (8.3%) using traditional methods. For the well B-8-23-23W4, the standard approach has an error of risk 0.075 (7.5%) chance of making a mistake on the formation rock quantity Figure 7.

Using a combination of primary core data and statistical analysis, the *K*c and Øc values were chosen as cut-offs. However, we assume that Øc and *K*c are correct, and the rock is deemed to be error-free values. If the *K*c is greater/less than the assumed one, the values of the (B and C) regions, and therefore the $Ø_{CR}$ and $Ø_{BE}$, will be impacted by the inaccuracy in *K*c and/or Øc.

The most precise NTG calculations can be obtained using the best porosity estimation $Ø_{BE}$ and *K*c. Porosity estimates for wells A-8-23-23W4 and B-8-23-23W4 are better when calculated using $Ø_{BE}$ instead of $Ø_{CR}$. The corresponding error rates for various $Ø_{CR}$ and $Ø_{BE}$ values are summarized in Table 2.

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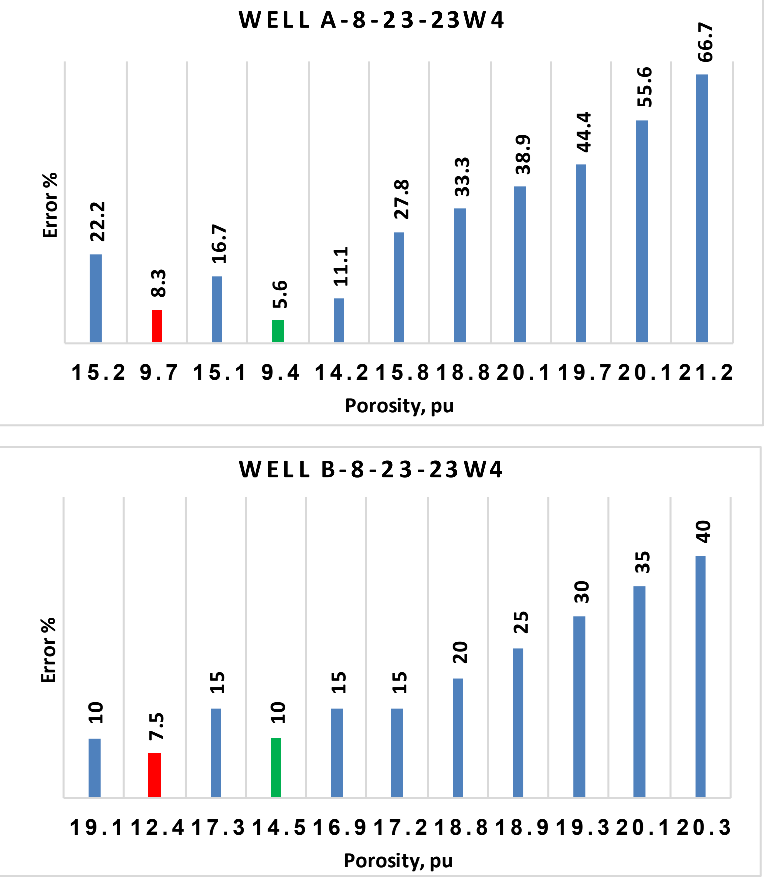

Figure 7: The sum of all mistakes made when trying to calculate the net pay of the chosen wells in the dataset. The Jensen and Menke method of cut-off is shown in green, whereas the conventional way is shown in red

Table 2. Demonstrates the different estimations for Øc of the studied wells

Well	$Ø_{CR}$	Error rate, %	$Ø_{BE}$	Error rate, %
A-8-23-23W4	9.7	8.3	9.4	5.6
B-8-23-23W4	12.4	7.5	14.5	10

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Since the probabilities of regions B and C are the same (equal), the best estimate for the Net-to-Gross ratio of NTG in well A-8-23-23W4 is $Ø_{BE}$= 9.4 pu Figure 8, with a margin of uncertainty of 5.6%. Using The $Ø_{BE}$, the error rate for false positives is lowered from 8.3% with traditional $Ø_{CR}$=9.7 pu to 2.7%.
In well B-8-23-23W4, the best Net-to-Gross ratio is $Ø_{BE}$=14.5 pu. Even though B and C have comparable probabilities, the 10% error rate is higher than $Ø_{CR}$=12.4 pu's 7.5% error rate. The optimistic porosity cut-off was chosen to predict NTG, even though other core data showed Øc = 19.1pu has the same 10% error rate. Data points on cross plots help pinpoint the exact location (area) of a mistake. It is the probability distribution of the porosity and permeability errors that determines the size of each area. All the ranges of Ø and *K* that the actual values of the rocks could fall into are shown area below. For instance, consider the well A-8-23-23W4 Figure 9. Despite the margin for error, point 1 is entirely inside region A. Point 2 is just as likely to be in either region A or C (50%) since it occupies both regions. Regions A, B, C, and D are occupied by a combined 25% in point 3.
Better estimates for cut-off and identification of net pay can be obtained by integrating geological, petrophysical, and engineering data with the core data provided. If Øc is required for net pay identification after computing probabilities in regions B and C, then minimize Prob (B) + Prob (C) or set Prob (B) = Prob (C) to estimate the net-to-gross ratio.
As a result of applying this suggestion, we discover that the well A-8-23-23W4 has a $Ø_{BE}$ = 9.4 pu, which may be used for identifying NPT and NTG since the total of the misidentification region is the smallest and provides an identical probability in both wells.

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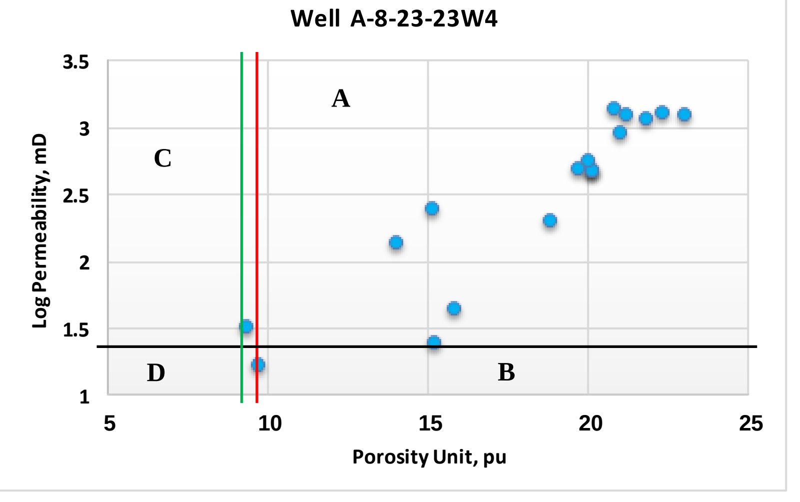

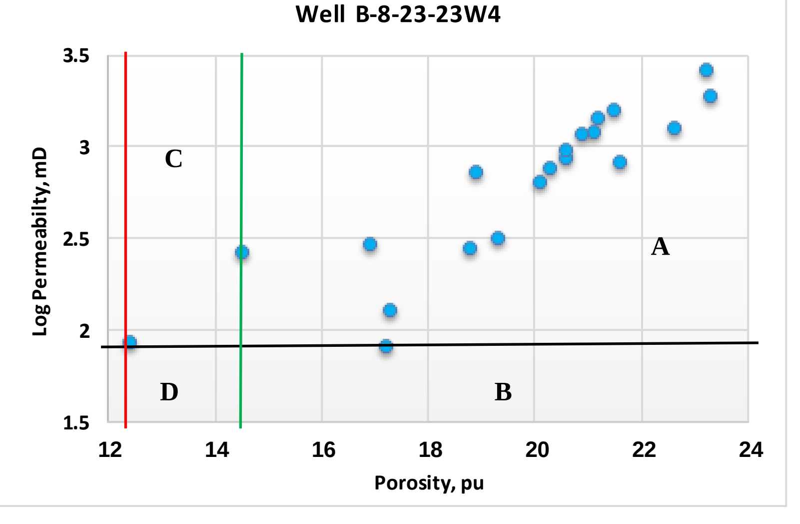

Figure 8: The glauconitic sandstone reservoir's porosity and permeability cross plot. Wells A-8-23-23W4 and B-8-23-23W4 use *K*c values 15 mD and 85 mD to solve the porosity cut-off (n=18 and n=20), respectively. "A" and "D" indicate non-pay and net pay regions respectively, and "B" and "C" were misidentified. Øc in (red) by the traditional method and (green) by Jensen and Menke

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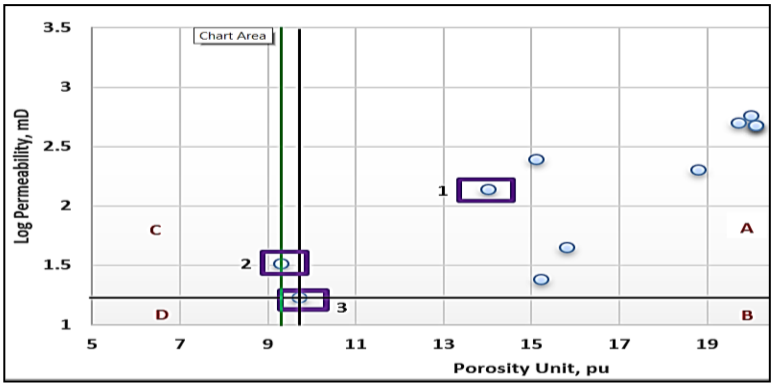

Figure 9: An illustration of square parts error zones for points 1, 2, and 3 within the well A-8-23-23W4 shows how much of each point occupies regions A, B, C, and D. Axis, Y is log *K* in mD, and X is porosity unit

Using $Ø_{BE}$ = 14.5 pu to estimate NTG for the well B-8-23-23W4 data set results in a 10% inaccuracy, whereas using $Ø_{BE}$ = 12.4 pu results in a 7.5% error to estimate NPT. The indirect method of utilizing Øc = $Ø_{BE}$ gives a reasonable estimate, although it is likely to be off by a factor of ΔØ = Ø - $Ø_{BE}$ using the standard deviation about the regression line.

Well, A-8-23-23W4's Øc is off by around 0.3 pu compared to the best estimate $Ø_{BE}$ values when using the least squares regression line fitted to the porosity and permeability, and the errors from the regression line cut-off are greater by 2.7% compared to the best estimate.

Well, B-8-23-23W4 has the best-estimated values $Ø_{BE}$ for NPT showing that the Øc obtained by using the least squares regression is the same cut-off values. The best estimate $Ø_{BE}$ for NTG, however, is different by 2.1 pu, although the error rate is lower when using the least regression line. The results of the effort to estimate cut-off values identify the net pay thickness and estimate the net-to-gross ratio are shown in Table 3**.**

Table 3. Summarizes the estimating of NPT and NTG by merging the integrated petrophysics data. Gross Reservoir Thickness (GRT)

Well	GRT, m	Porosity Unit			NPT, m		NTG	
		Øc	$Ø_{BE}$		Øc	$Ø_{BE}$	Øc	$Ø_{BE}$
			NPT	NTG				
A-8-23-23W4	7.13	9.7	9.4	9.4	6.43	6.43	0.9	0.9
B-8-23-23W4	4.62	12.4	12.4	14.5	4.62	3.71	1	0.8

As a result, initially, the negligible difference between traditional estimation and the Jensen and Menke technique in this instance may be attributed to the few numbers of core samples. Utilizing a greater number of porous samples can yield superior results.

Secondly, the strategy employs a probabilistic methodology to establish porosity cutoffs, offering a more statistically robust foundation than arbitrary or heuristic cutoffs. Furthermore, it seeks to reduce the inaccuracy in determining the net-to-gross ratio, resulting in enhanced reservoir characterization accuracy.

Third, by integrating probabilistic components, more effectively addresses the intrinsic uncertainty in petrophysical observations and interpretations. The approach can also consider economic aspects, aiding in the equilibrium of costs and revenues for varying oil/gas prices while establishing cutoffs.

Fourth, in contrast to traditional confident cutoff methods, Jensen and Menke's approach can yield more precise net pay assessments, particularly in heterogeneous reservoirs. Furthermore, unlike binary pay/non-pay classifications, this method offers a more nuanced evaluation of reservoir quality at varying depths.

Finally, the approach applies to a range of petrophysical characteristics beyond porosity, including shale volume and water resistivity, hence demonstrating versatility across diverse reservoir types and conditions.

Despite all the advantages of employing the Jensen and Menke approach for cutoff estimation described above. There are additional drawbacks; a significant concern is the difficulty of computing. The computation of the cutoff using this method was

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protracted and challenging to estimate and verify, even with a small core sample.

Jensen and Menke developed a probabilistic method for determining porosity cutoffs, which can be beneficial in certain instances; nevertheless, it may not consistently encompass the complete intricacies of reservoir attributes. The method employs a probabilistic approach akin to the best-fit line technique, potentially oversimplifying the intricate properties of reservoirs.

A notable limitation of the Jensen and Menke technique is its failure to explicitly consider fluid characteristics. Conversely, more complete methodologies utilize mobility cutoff as a foundational criterion rather than permeability, considering both rock and fluid characteristics.

Utilizing methods that heavily depend on statistical methodologies, such as those of Jensen and Menke, poses the risk of eliminating suboptimal sections that could potentially enhance reservoir connectivity and dynamics. This may result in an inaccurate depiction of the reservoir model from both static and dynamic viewpoints.

In summary, although the Jensen and Menke cutoff estimation provides useful insights into historical performance and risk-adjusted returns, its efficacy in forecasting future portfolio performance is constrained. Investors and portfolio managers ought to employ this strategy as one of several instruments in their decision-making process, rather than depending solely on it for forecasting future performance.

4. CONCLUSION

- Although the search results do not present specific quantitative comparisons of accuracy between the Jensen and Menke method and alternative approaches, the method's probabilistic characteristics and capacity for graded assessments imply it may yield enhanced accuracy compared to traditional crisp cutoff methods in numerous situations. Nonetheless, like any methodology, its efficacy may fluctuate based on the properties of the reservoir and the data at hand.

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- To further define and evaluate NPT and NTG for the examined wells inside the glauconitic sandstone formation in Blackfoot Field, Alberta, a genuine study case and innovative perspective are offered for selecting porosity cut-off values using core data and statistical analysis.
- Shaly sand reservoirs are examined and evaluated using this study. One quantitative approach to better-characterizing reservoirs is discussed in this article. The integration of cores and statistical data is also intended to define net pay estimation and NTG ratio.
- The decision of where to draw the line must be made on a case-by-case basis. Estimating reserves is a difficult task that is affected by several factors, not all of which are immediately apparent.
- Geological cores and statistical analysis were used to calculate the well's net pay for the reservoir under scrutiny. Using least-squares regression to predict porosity (or permeability) cut-off values from known data introduces the possibility of erroneous predictions.
- Whether the cut-off is used to determine the intervals of net pay thickness or net-to-gross ratio, the optimum estimate for porosity varies. However, the estimation of the threshold can be modified to account for inaccurate measurements.
- In conclusion, it is easy to talk about net pay but harder to put a number on it. Very few, if any, procedures exist for determining net pay. It is hoped that by analyzing petrophysical, engineering, and geological data for the chosen wells, this article will provide a clearer definition of net pay and influence the process of counting accurate cut-off values.

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