Evaluation of Contingent Resources

Kiskunhalas Tight-Gas Sand Project, Hungary

March 10th, 2024

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CANCAMBRIA
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Dr A. Bustin, Ph.D., P.Eng.
6149 Brodie Rd
Delta, BC
V4K 2B8

March 1st, 2024

Dear Dr Bustin,

Re: Engagement to evaluate the oil and gas resource with the BA-IX Mining Licence, Hungary.

Please accept this letter with regards your engagement by CanCambria Energy Corp for your evaluation of the Company's oil and gas resource relating to our 100% owned BA-IX mining licence, Hungary, and your independent appraisal of these resources effective March 1st, 2024 (the effective date). We herein confirm, to the best of our knowledge and belief, the following representations during the conduct of your resource evaluation.

1. We (the Client) have made available to you (the Evaluator) certain records, information, and data relating to our property. We confirm the information is complete and accurate as the effective date including the following:

   Our asset ownership of the property,
   Details concerning the geology of the BA-IX licence and adjacent areas,
   Details regarding the drilling, testing and production of previous wells,
   Accounting, financial, tax and contractual data as it relates to the BA-IX mining licence.

2. We confirm that all financial and accounting information provided to you is entirely consistent with that reported by our Company for public disclosure and audit purposes.

3. We confirm that our company has satisfactory title to the asset.

We look forward to the completion of your report.

Yours very truly,

"*Christopher Cornelius*"

Dr Chris Cornelius PhD
President and CEO

CanCambria Energy Corp.
1120 - 625 Howe St.
Vancouver, BC, CANADA V6C 2T6
info@cancambria.com

Introduction

CanCambria Energy, Corp. (the “Company”) holds 100% working interest (WI) in the BA-IX Mining License (the “Property”), acquired in 2023. The license area is located in south-central Hungary (Figure 1) and comprises approximately 132 km^2 of flat, agricultural land.

Depth rights range from 1,150m to 6,000m TVD, with a net revenue interest (NRI) of 98% for unconventional production. The license area covers the prospective part of the Kiskunhalas Trough (a.k.a. Kiskunhalas Field), a high-temperature high-pressure (HTHP) Miocene Basin that contains three deep legacy exploration wells. Collectively, these wells and associated data and testing confirm a gas/natural gas liquids discovery. Legacy three-dimensional (3D) seismic data further constrain the size of the gas/natural gas liquids pool, at more than 7,500 acres. All play elements of the petroleum system have been proven. A comprehensive appraisal program wholly funded by CanCambria Energy Corp. is underway to commercialize the field.

The asset is designated as unconventional, due to the tight (low permeability) nature of the Miocene reservoir. In accordance with the COGE Handbook, the tight sand gas and natural gas liquids present in the Property are classified as Contingent Resources with the project maturity sub-class Development Unclarified. As tight sand gas does not match one of the defined product types, the closest product type chosen is conventional natural gas.

The Company engaged Dr. Amanda Bustin, P.Eng., an independent, qualified reserves evaluator, to evaluate the contingent conventional natural gas and natural gas liquids resources in the Property. These Contingent Resources are presented and described in this Report. Insufficient data are available for an economic evaluation.

The evaluation was prepared in accordance with the definitions and guidelines set out in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and in compliance with the requirements of the Nation Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”).

This resource evaluation was completed in March 2024. Estimates of resources were prepared using seismic, geological, and well information from the Company to approximately January 1st, 2024. The Company has confirmed that, to the best of its knowledge, all information provided to Dr. Bustin is correct and complete as of the effective date of March 10th, 2024.

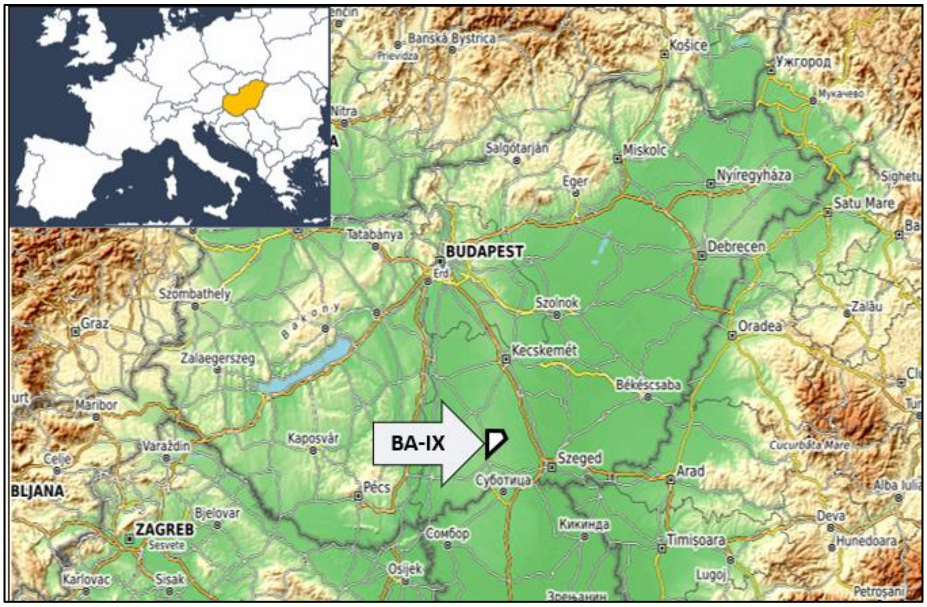


Figure 1. Location of BA-IX Mining License, Hungary

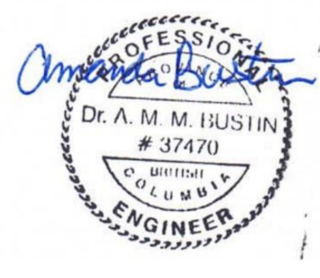
Certificate of Qualification

Amanda M.M. Bustin, Ph.D., P.Eng.

The report entitled “Evaluation of Contingent Resource: Kiskunhalas Tight-Gas Sand Project, Hungary, effective March 10, 2024 (the “Report”), was prepared by Amanda M.M. Bustin, Ph.D., P.Eng. for CanCambria Energy Corp. (the “Company”).

I, Amanda M.M. Bustin Ph.D., P.Eng., President of Bustin Earth Science Consulting, 6149 Brodie Rd, Delta, British Columbia, declare the following:

1. I hold the following degree:
    a. B.A.Sc., Geological Engineering (2001), University of British Columbia, Canada.
    b. Ph.D. (2006), University of Victoria, Canada.
2. I am a registered professional:
    a. Professional Engineer (P.Eng.), Province of Alberta, Canada
    b. Professional Engineer (P.Eng.), Province of British Columbia, Canada
3. I am a member of the following professional organizations:
    a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
    b. Engineers and Geoscientists British Columbia (EGBC)
4. I am a qualified reserves evaluator as defined in:
    a. the “Canadian Oil and Gas Evaluation Handbook” as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter)
5. My preparation of the Report is based on my engineering knowledge and the data provided to me by the Company.
6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the Report or in the securities of the Company.



March 10, 2024

Amanda M.M. Bustin, Ph.D., P.Eng.

Summary

Table 1. Summary of Gross Lease (100% WI) Best Estimate (C2) Development Unclarified Contingent Resource

Gross Unrisked DGIIP		Recovery Factor	**Gross Unrisked C2 Contingent Resource**		Chance of Development	**Gross Risked Contingent Resource**	
Conventional Natural Gas (billion ft^3)	Natural Gas Liquids (million bbl)		Conventional Natural Gas (billion ft^3)	Natural Gas Liquids (million bbl)		Conventional Natural Gas (billion ft^3)	Natural Gas Liquids (million bbl)
1888	226.5	0.61	1151	138.1	0.72	828.6	99.4

Table 2. Summary of Company Interest (98% WI) Best Estimate (C2) Development Unclarified Contingent Resource

Gross Unrisked DGIIP		**Gross Risked Contingent Resource**		**Company Interest Risked Contingent Resource**	
Conventional Natural Gas (billion ft^3)	Natural Gas Liquids (million bbl)	Conventional Natural Gas (billion ft^3)	Natural Gas Liquids (million bbl)	Conventional Natural Gas (billion ft^3)	Natural Gas Liquids (million bbl)
1888	226.5	828.6	99.4	812.0	97.4

Table 3. Summary of Chance of Development

Resource Class	Corporate	Market Access	Infrastructure	Regulatory	Economic	Timetable for Development	Chance of Development	Project Maturity Sub-Class
Contingent	0.95	1	0.95	0.95	0.86	0.98	0.72	Development Unclarified

Discussion

This Report provides a summary of Contingent Resources in the Kiskunhalas Trough, Hungary permit area (the "Property") of CanCambria Energy Corp. ("CanCambria or the "Company"). In accordance with the COGE Handbook, the tight sand gas and natural gas liquids present in the Property are classified as Contingent Resources with the project maturity sub-class Development Unclarified. As tight sand gas does not match one of the defined product types, the closest product type chosen is conventional natural gas.

The Best Estimate (C2) Development Unclarified, Contingent Resources in the Property are assigned based on previous well logs, well samples and production tests, in addition to legacy seismic data acquired on the Property. The estimates of Contingent Resources were prepared using volumetric methods.

This Report does not include an economic evaluation of the Company's Contingent Resources.

An on-site inspection of the Property was not conducted for purposes of this report by Dr. Bustin because the project is at a pre-development stage, with no existing wells or facilities.

Contingent Resources should not be confused with reserves. Actual resources may be greater than or less than the estimates provided herein. There is uncertainty that it will be commercially viable to produce any portion of the resources. There is uncertainty as to the timing of such development.

Supporting Information

1. Historical Activity

The BA-IX Mining License (the "Property'), a contiguous triangular block, resides within a proven petroleum basin (Figure 2). There is significant production from numerous E&P ventures over several decades including shallow oil and gas wells and dry holes. Within the Kiskunhalas Trough, two deep (>4,000m) exploration wells were drilled in the late 1980s, by a consortium including MOL plc, World Bank and US Geological Survey. The first well, Kiha-I was spud in mid. 1986 using 2D seismic data only, it was positioned roughly in the basin center. The well reached TD in 1987 and recorded over-pressured gas sands from 2,200m to 4,300m TVD consistent with an early Miocene age. The well logged and cored this gas column but did not encounter any significant high-quality reservoir. A second well, Kiha-DI was drilled one year later and leveraged a (1980s vintage) 3D seismic survey; this well was located up-dip and within a very crude amplitude anomaly taken as a proxy for a gas "bright-spot". The well again recorded a significant over-pressured Miocene gas column; however, the Kiha-DI logged several high-quality reservoir sandstone intervals. DST rates of up to 0.3 MMcf/d natural flow (per zone) were recovered. The well was not completed as a producer and was subsequently abandoned. More recently, an appraisal well, Ba-E1 was drilled by E&P company RAG Austria AG in 2008 and completed as a producer in the Miocene, located 500m offset to the Kiha-DI. This third well represents the last activity in the field, the Ba-E1 well flowed gas/natural gas liquids (post stimulation) to sales for several months, before being abandoned due to a combination of low rates and low commodity prices. Well data indicate that reservoir pressure in the target zone exceeds a 0.85psi/ft gradient with a bottom hole temperature in excess of 175°C.

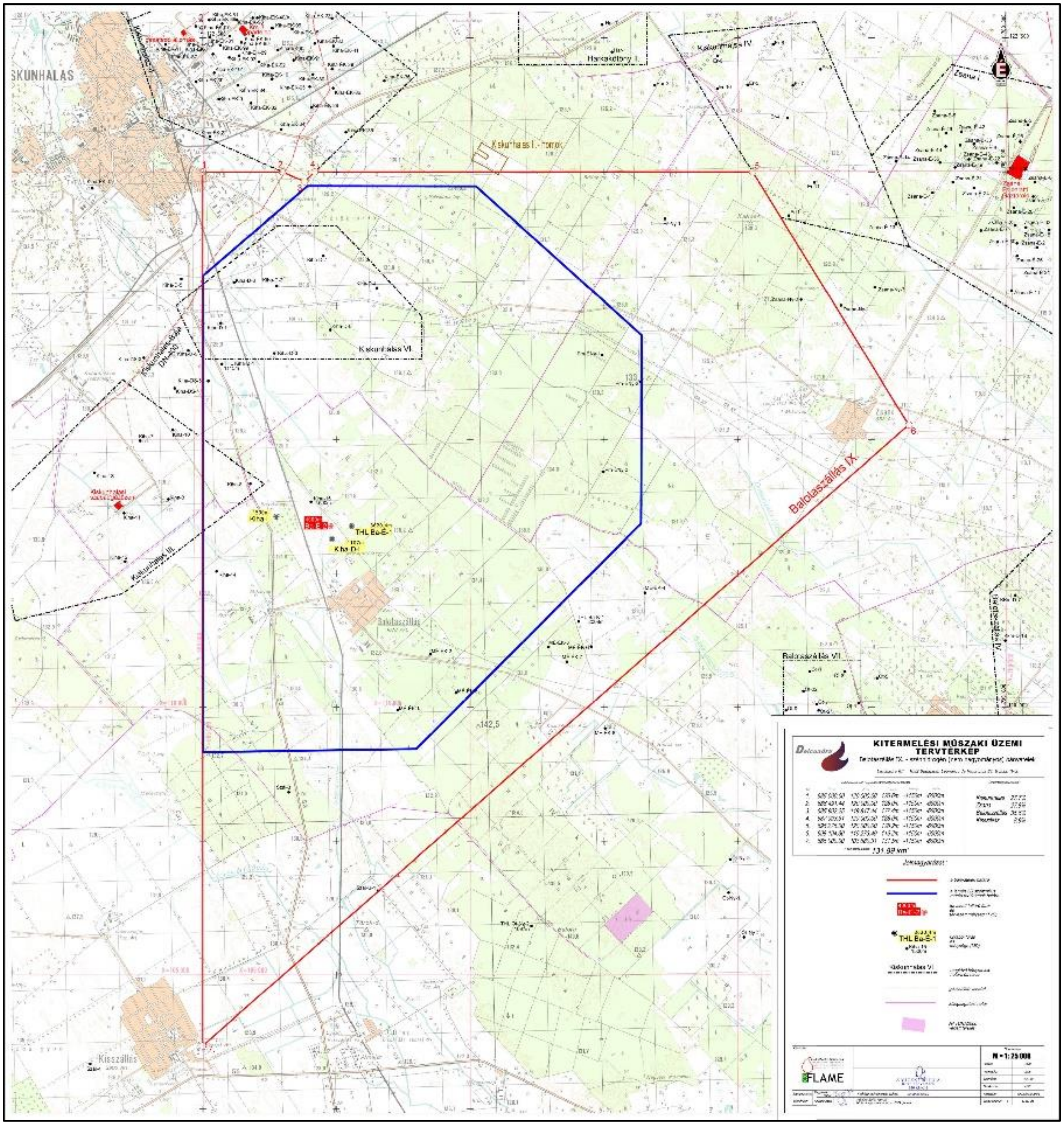


Figure 2. Location map of the BA-IX Mining License (red outline). The Kiskunhalas Trough focus area in highlighted in blue, the three legacy wells are shown in yellow

2. Geological Overview

The Kiskunhalas trough is a deep, narrow sedimentary basin genetically related to other coeval hydrocarbon bearing basins in the region, including the Mako Trough and Berkes Basins. Collectively, these basins form part of the greater Pannonian system, a large back-arc basin that encompasses Hungary and several adjacent counties.

Rapid burial of the early Miocene section (including source rocks) into the gas-window generated significant volumes of hydrocarbons. The target section in the Kiskunhalas Trough is however at significantly shallower depth present-day, than the offset basins due to Alpine-age basin inversion and uplift. Overpressure is directly related to gas generation and charge (within a closed system), while high heat flow is attributed to crustal thinning within the back-arc basin setting. The thick post-rift section is well developed and provides a good regional top-seal.

2.1 Structure (Trap)

The Kiskunhalas Trough is an elongated strongly asymmetrical strike-slip (pull-apart) basin, approximately 7 km wide and 20 km long, trending NE to the SW across the BA-IX Mining License. The trough is defined by a series of high-angle (poorly resolved) NE/SW trending faults along the northern margin (down-thrown to the south) and a more subtle, sub-parallel fault trends defining the western and southern margins of the trough. Apparent dextral motion promoted a pull-apart (rift-style) basin along the master fault strand. The sedimentary fill appears coeval with the main fault growth (syn-rift) and propagation, with the greatest sediment accumulation in the south-central portion of basin. A series of erosional unconformities and facies pinch-outs define the eastern basin area. Several intra-basin normal faults are also suggested from legacy 3D seismic data. However, limited insights can be gained from this seismic data, including the deep structure, due to low fold and short offsets. New proprietary 3D seismic will provide internal characterization of the basin and assist future appraisal. In general, strata dip at low angles towards the southwest. Present day stress data from image logs and sonic scanner data confirm a tensional regime with a N/S principle (max) horizontal stress, with minimal stress anisotropy.

Figure 3 illustrates the architecture of the basin and the inter-bedded nature of the source, seal, and reservoir units. With the onset of basin inversion, the syn-rift Miocene section experienced E-W directed shortening that resulted in large fault reactivation and broad folding that created the main trapping geometries discussed further in Section 3.

The syn-rift package is capped by a thick post-rift section, including a well-developed shale that serves as a regional top seal. The post-rift is also deformed to a lesser extent by localized compaction and subsidence expressed as small offset faults that produced several small structural traps in the overburden.

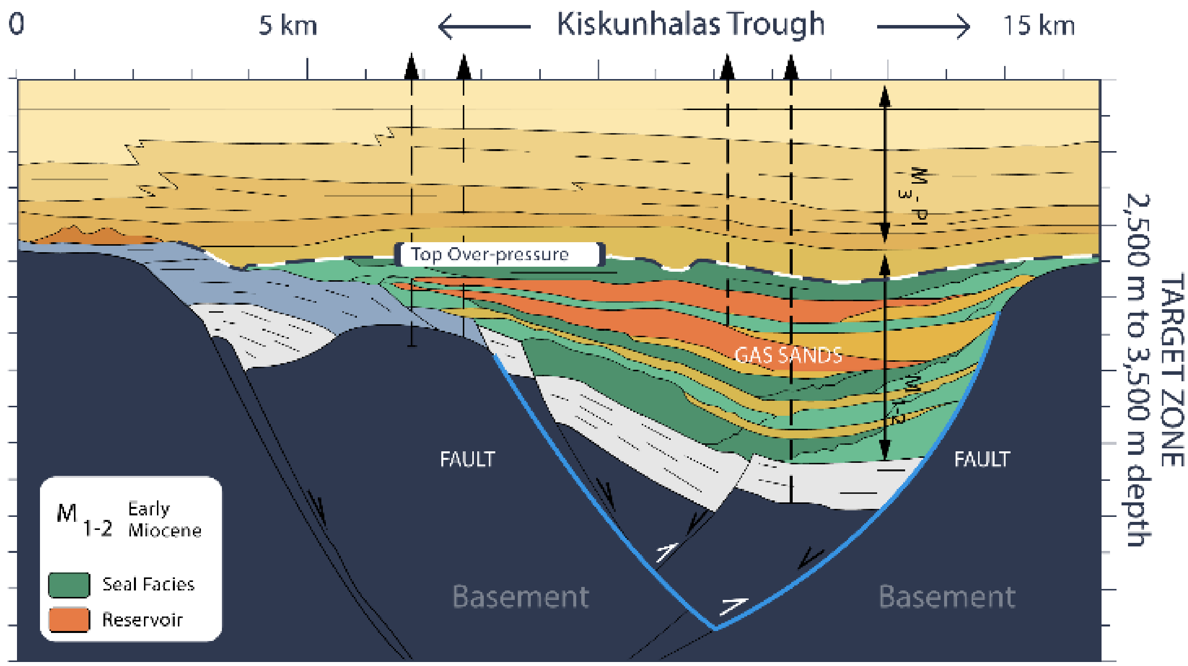


Figure 3. West-east basin cross-section showing main elements.

2.2 Stratigraphy (Reservoir)

The regional stratigraphic framework of the region is shown in Figure 4 and is dominated by Neogene Period strata (23–5 million years ago). The tight-gas sandstone target interval is dated using biostratigraphy to the early Miocene Series. The top of the tight-gas reservoir interval (~2,100m TVD) corresponds broadly to the onset of sustained gas shows and overpressure. This interval is informally named the Lower Kiskunhalas Formation and attains a gross thickness of 1,000m. This interval is dominated by syn-rift basin-fill, with well-sorted sandstone, shale and conglomerate facies deposited in a dynamic (faulted) basin margin to deep lacustrine setting. A high degree of lateral facies variability is observed from the available well data.

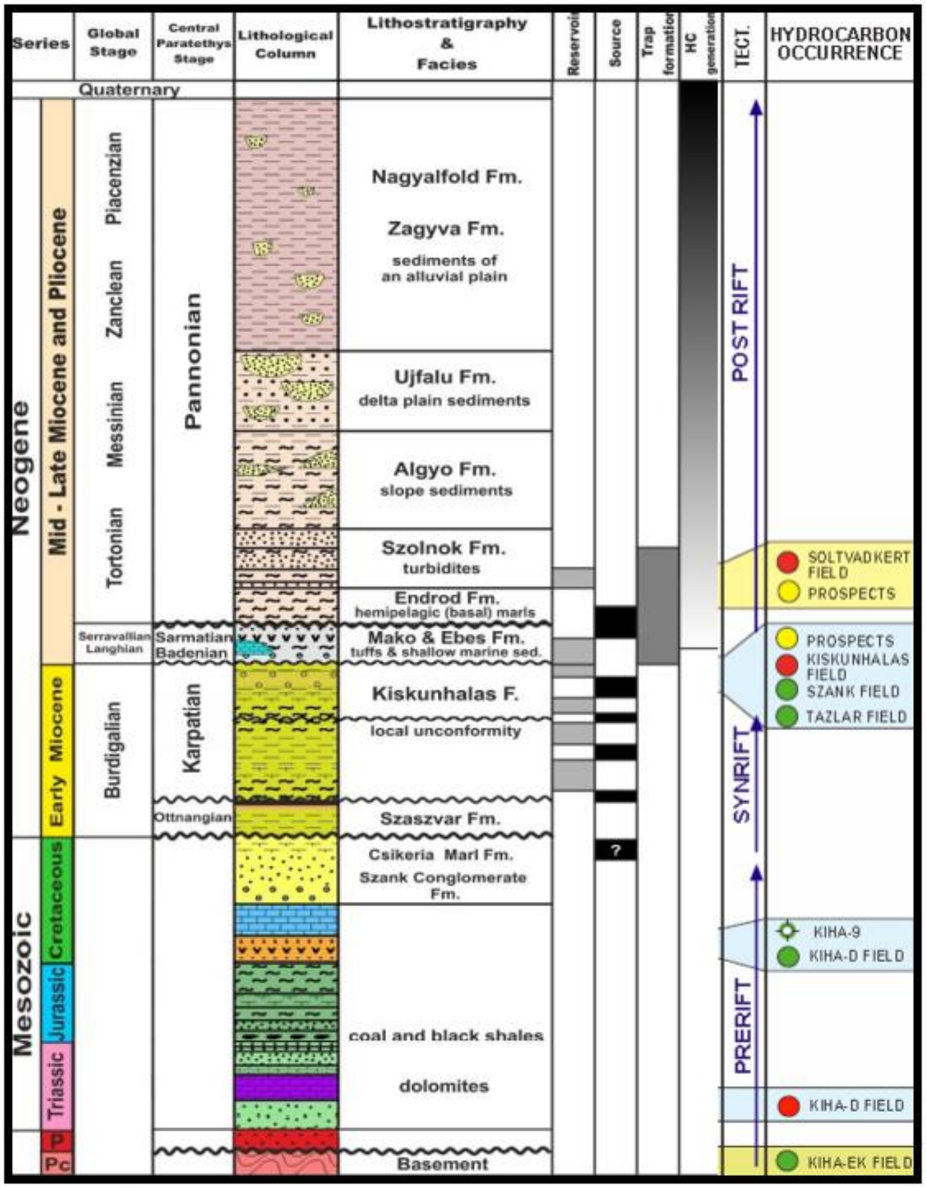


Figure 4. General stratigraphy highlighting petroleum elements

The syn-rift succession records the rapidly subsiding basin and is characterized by highly discontinuous strata. Provenance is interpreted to be sourced from the adjacent margins of the basin, with numerous point-sources for sediments fed locally by rivers and deltas. A proximal to distal transition within the basin may be expected with fan-deltas and local gravity driven fault scarp (debrites) facies grading into basin floor fans (lobes and channels) and low-density turbidities. A background lacustrine hemipelagic system dominated. Figure 5 integrates the core observations with the fault-related sedimentation model. It is interpreted that sediment distribution patterns were related in part to the proximity of faults and relay ramps, which controlled the rate of accommodation. Reservoir quality geo-bodies include bars, lobes, sheets, and channel fills that attain a maximum thickness up to 20m. The distal facies, off-axis, are generally thinly bedded to laminated with low porosity.

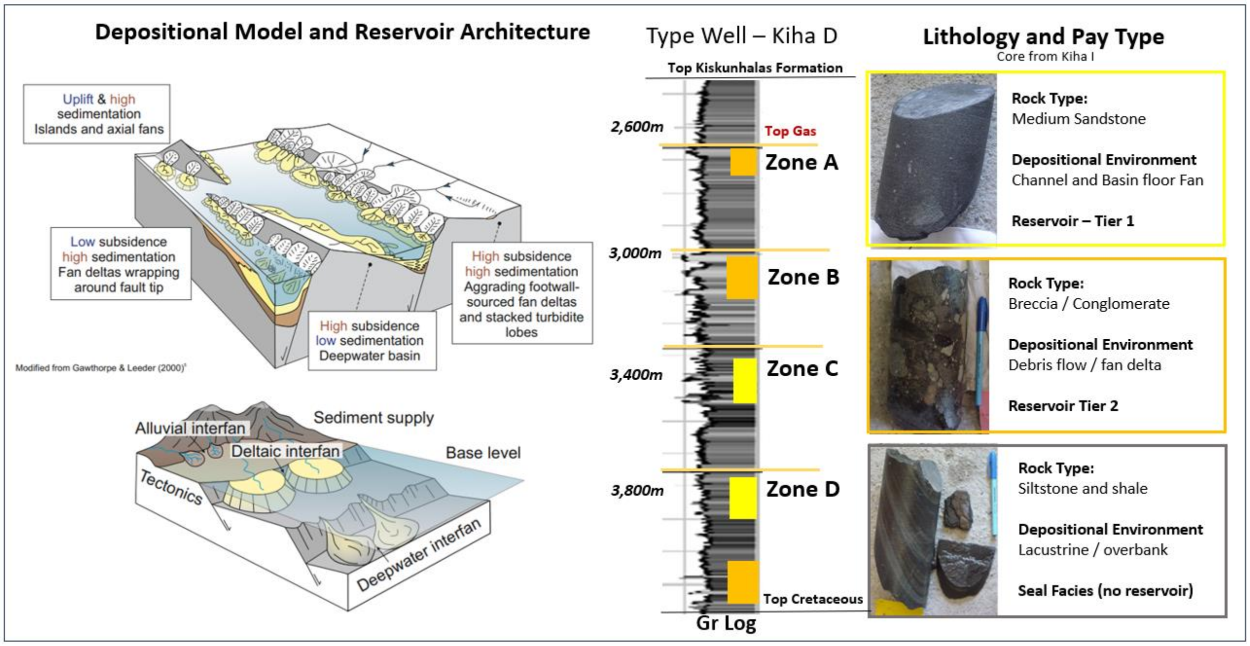


Figure 5. Type log and facies model. Leveraging core from Kiha-I discovery well

2.3 Petroleum System

The greater Pannonian Basin is designated a global "super-basin" and has cumulative hydrocarbon production over 13 billion BOE. Collectively, the legacy data within the Kiskunhalas Trough prove-up all elements of the petroleum system, including a (I) mature source, (II) high quality reservoir, (III) combination traps, (IV) optimal timing, and (V) overburden/preservation. The tight gas play is designated as a discovery and there is minimal geologic risk. No down-dip free water was encountered, and lowest known gas is defined by the Kiha-I well (discussed in section 4). Gas charge is by capillary displacement of water from local migration or self-sourced interbeds. Source rock analysis and characterization includes TOC and rock-eval-pyrolysis on cores and cuttings from field wells and confirms a commercially viable source rock. Vitrinite reflectance results up to 1.3 Ro constrain the wet-gas window, within the HC "kitchen".

3. Seismic Interpretation

There are numerous old 2D seismic lines covering the general area of the BA-IX Mining License area; following the field discovery by the Kiha-I well, the "Kiskunhalas 3D" seismic survey was acquired in 1986. The seismic survey was acquired by CGG using a dynamite source and covers a large area over 150km^2. CanCambria purchased a license to this survey and has interpreted the pre-stack time migration (PSTM); data quality is moderate with poor reflectivity in the deeper portions of the basin. Basic interpretations of the main structural and stratigraphic elements were made using this 12-fold data.

Well ties were undertaken by CanCambria using the sonic, density and VSP data from the legacy wells. The synthetic seismograms demonstrate strong seismic response due to highly variable acoustic impedance in the target zone. The rocks in general are hard and fast, but the velocities do "slow" in a relative sense within the target zone due to over-pressure. Well ties are robust and reflectivity is sufficient to allow basic interpretation the reservoir and trap. The Badenian unconformity defines the transition from syn-rift to post-rift. Figure 6 comprises a typical seismic section across the basin in an E-W arbitrary line. A prominent series of reflectors are mapped within the Kiskunhalas Formation target zone, including top gas (aka Zone A) and a very prominent regional trough amplitude (Zone B) that is taken to represent a proxy for the overall trap geometry. The basement is very poorly imaged.

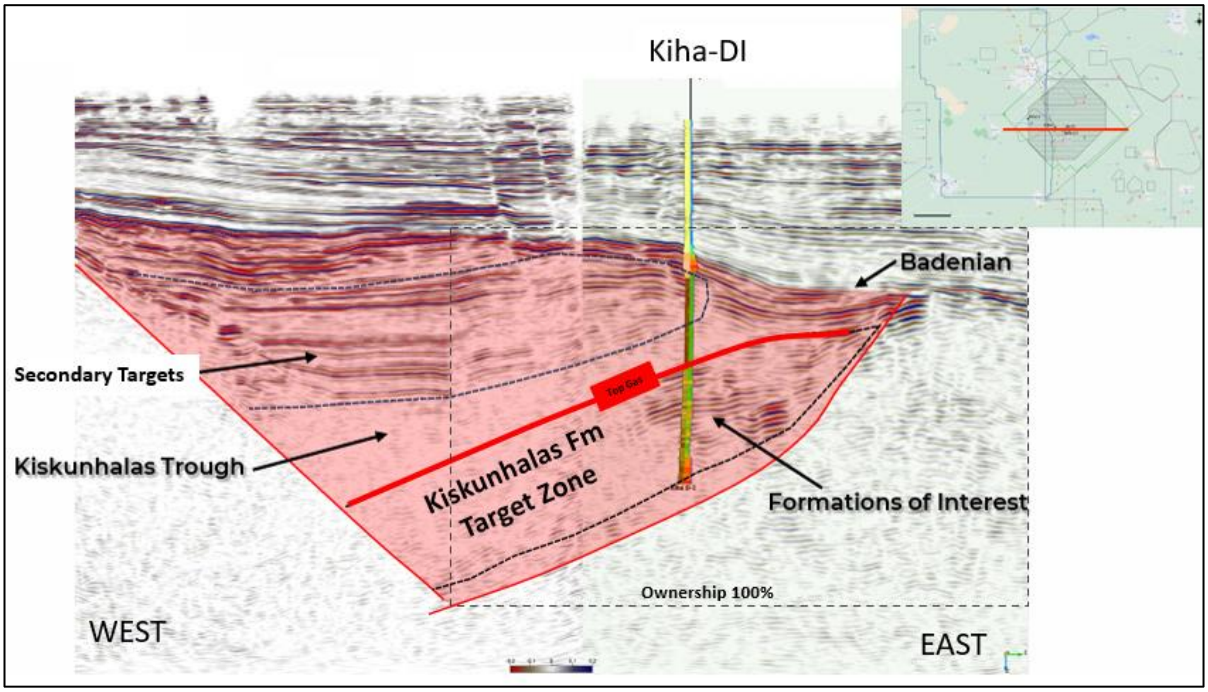


Figure 6 Arbitrary seismic section E-W across the Kiskunhalas Trough (highlight target zone)

The "top gas" horizon (aka Zone A) and Zone B reflectors are used to define the upper limit of the structural trap that is mapped in Figure 7. A broad monoclinal dip with local antiformal roll defines the trap. Structural closure may exceed 1,200m, including numerous smaller scale stratigraphic pinch-outs in the NE up-dip direction. The margins of the basin are delineated by high-angle strike slip fault strands while the up-dip margin is defined by a series of large erosional unconformities and facies pinch-out. The prospective area is defined structurally as the area up-dip from the Kiha-I well (this well is considered transitional to "wet"). An approximate 7,500-acre area is designated as prospective and is used as the input for resource evaluation. It should be noted that the stacked pay section may have multiple local and dynamic fluid contacts.

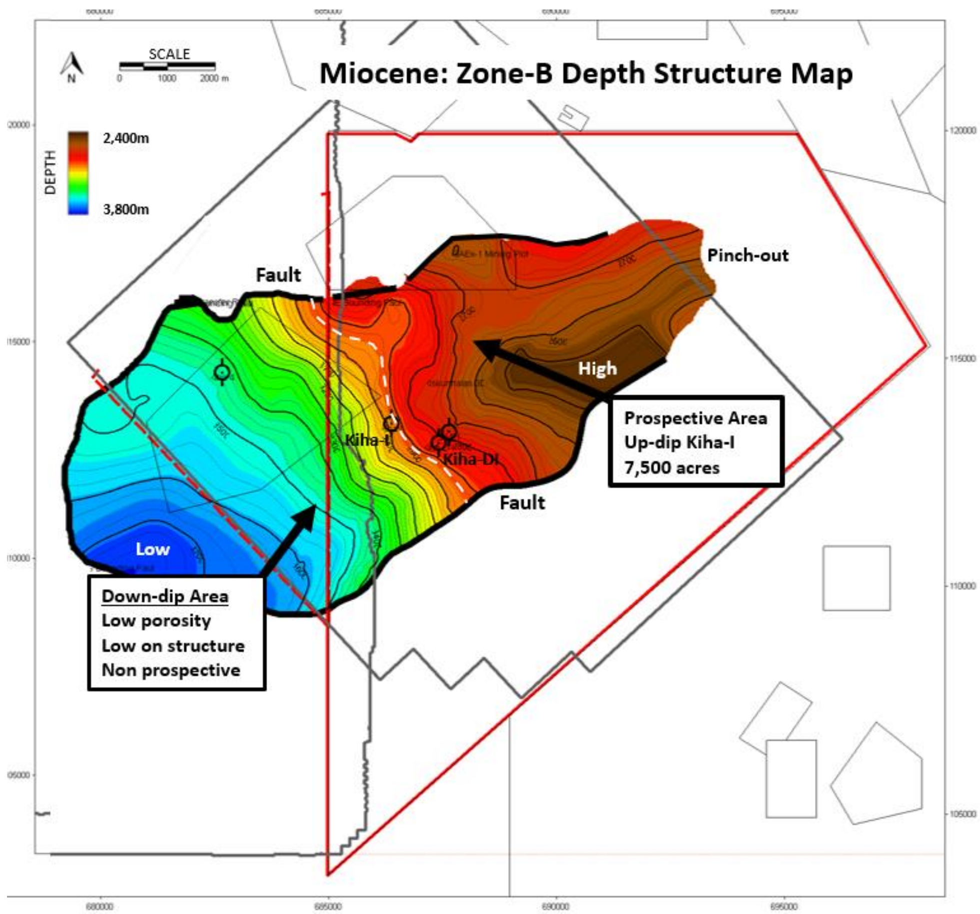


Figure 7. Structure Map Zone B (prospective area) from legacy 3D seismic

4. Petrophysical Analysis

This report is based upon an independent log evaluation of the three key wells in the field by CanCambria Energy and represents a significant improvement upon the old log model used by the legacy operator. The reservoir has multiple, stacked gas-charged geo-bodies with a gross gas column greater than 1,000m. Multiple stacked gas accumulations are typical with limited movable water. The prospective area is defined up-dip of the Kiha-I well. Interpretations are based upon analysis of older vintage e-logs, with a standard quad-combo (gamma-ray, resistivity, and neutron density) suite. Advanced logs including image logs help refine the geologic model, while mud logs and drilling data supplement the results.

The Kiha-DI well is the type well for the field, with over 75m of high-quality net pay. The pay section corresponds to a depth of 2,650m to 3800m TVD, below a depth of 4,000m porosity appears to decrease dramatically. All four zones (A, B, C & D) contribute varying amounts to the net pay, with Zone C carrying the best net pay thickness and overall reservoir quality. Figures 8 and 9 illustrate the typical petrophysical analysis results for Zone B and Zone C respectively, which record good quality sands with a low net-to-gross ratio. DST stations are highlighted on the log panels and discussed in Section 5.

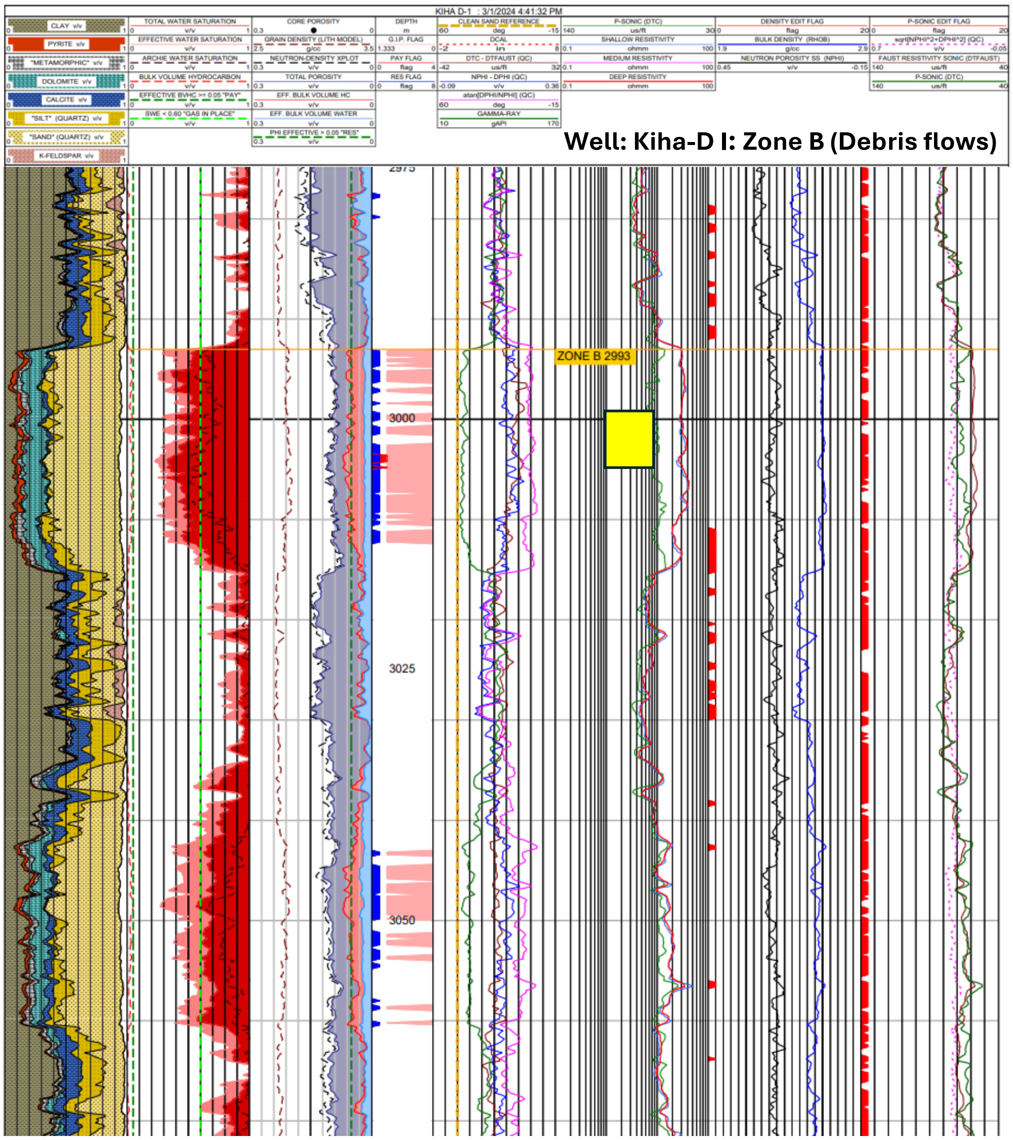


Figure 8. Petrophysics – Zone B (from Kiha-DI "type well") Yellow box is DST #4/4

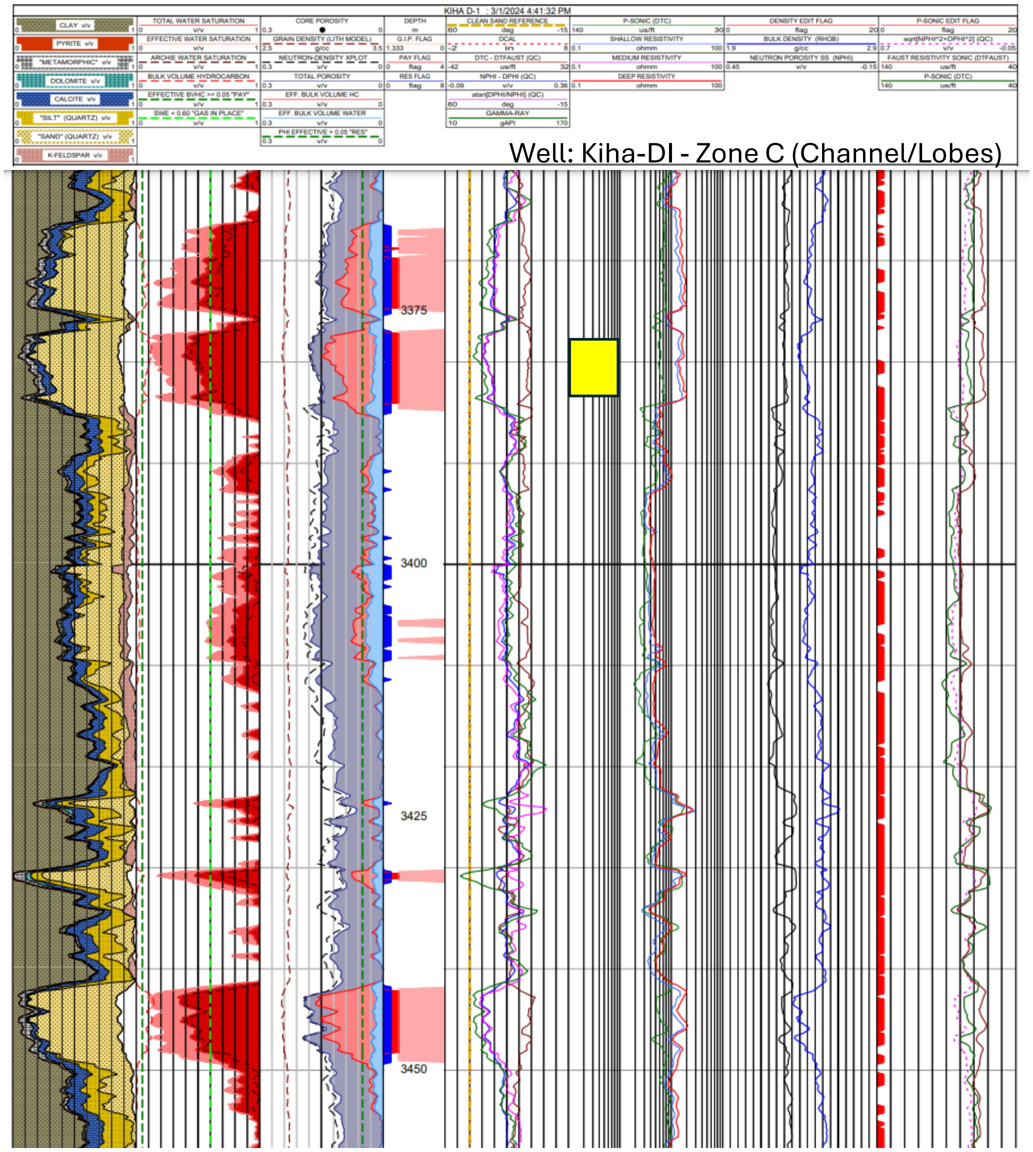


Figure 9. Petrophysics – Zone C (from Kiha-DI “type-well”) Yellow box is the DST # 2/2

The Kiha-I well was drilled in a relative down-dip position and may represent the southwestern limit of the play area. The gross Kiskunhalas Fm interval exceeds 1,000m, and although sand is present, water saturation is elevated, typically 55% or higher and considered a transitional zone; a downdip limit of 2,950m TVD is used to define the trap at the level of Zone B.

The 2008 Ba-E1 appraisal well was drilled some 700m offset from the Kiha-DI and although the well encountered a locally thin pay section, the well was completed and flowed gas to sales (Section 6). Post-drill well analysis indicates proximity of an intra-basin fault. This fault was not resolved from the legacy 3D seismic but appears to have cut out one or more prospective zones. Furthermore, the well is located on the footfall (high-side) of the fault, with a thick coal seam in the well, near the base of Zone C, indicating the area was high and near the basin margin. This scenario would divert reservoir quality sand deposition away from the area, focused toward the basin lows. Figure 10 illustrates the relative structural high of the Ba-E1 well, relative to the type well (Kiha-DI) which does not have any basin margin (coal) facies.

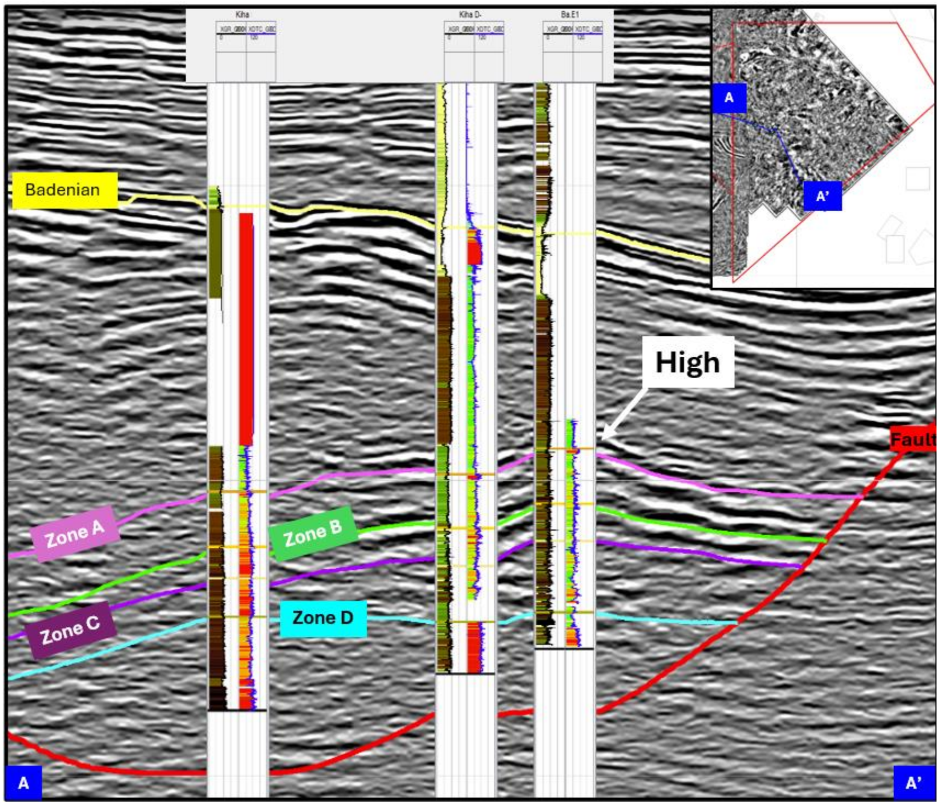


Figure 10. Well to seismic tie (Zones A to D)

Consequently, the Ba-E1 well is considered abnormal with respect to reservoir distribution and resulting net pay. This learning is implemented in the resource evaluation by decreasing recovery factors for the field; net pay is not directly input from the Ba-E1. Areas impacted by faults are interpreted to be no more than 10% of the total basin area. This demonstrates the necessity for new high-quality 3D seismic to resolve geo-hazards, including faults and better delineate reservoir thickness and quality.

Net pay characterization is a key variable for field appraisal and is defined in this evaluation by effective porosity of 5% or greater, with a water saturation at or below 60%. While gas saturation is broadly predictable at the basin scale, porosity is more variable and contingent on facies type. Porosity appears to be related to depositional environment, where textural and compositional maturity exerts a first-order control of the pore system. Sandstone bodies attributed to reworked lobes, sheets, and channels, carry the greatest effective porosity up to 14%. Breccia and conglomerate facies that result from gravity processes such as debris flows have lower effective porosity (6.5%). For this reason, the log model integrates lithology, rather than a simple gamma-ray log proxy, for rock type(s). Standard Archie electrical properties were used to calculate water saturation. Core data was collected from the Kiha-I, and the log model is calibrated with these data.

The type well which has 75m of net pay is utilized for the resource estimation and based largely upon Kiha-DI. A four-fold subdivision of the target zone is shown:

- **Zone A** (net pay 7m) - 8.5% effective porosity & Sw 29%
- **Zone B** (net pay 26m) – 6.5% effective porosity & Sw 33%
- **Zone C** (net pay 32m) - 12.5% effective porosity & Sw 22%
- **Zone D** (ne pay 10m) - 8% effective porosity & Sw 40%

TOTAL Net Pay 75m

While no areas with higher net pay than this type well have been modeled, there may exist upside potential (not captured in the resource estimates) for greater sand accumulation in certain favorable areas of the field. Net pay prediction is a key challenge and significant opportunity for the development of the Kiskunhalas play and is discussed further in Section 7.

5. Production and Test Data

Production data for the Kiskunhalas tight-gas sand play is somewhat limited, below are the results from two key field wells. There is currently no production from any wells in the field.

Kiha-DI

Several drill stem tests (DSTs) were completed in the Kiha-DI in 1989; these temporary tests isolated individual zones within the wellbore to assess natural (unstimulated) reservoir flow rates and deliverability (including pressure drawdown). Six test intervals have been identified by zone below. Results range from hydrocarbon shows to significant flow rates and appear consistent with log analysis results, with Zone C having the best productivity with a combined natural flow rate of 0.55 MMcf/D from two zones containing 10m of net pay. DST intervals corresponded to:

Zone			
A	Test 5/6	2674-2681m	Oil and gas shows
A	Test 5a/6	2674-2681m	HC shows after acidizing
B	Test 4/4	2999-3007m	HC shows plus oil
C	Test 3/4	3148-3152m	**0.3 MMcf/D gas +cond.** on 2mm choke (thin sand)
C	Test 2/2	3377-3384m	**0.25 MMcf/D gas,** died 5hours, mechanical blockage
D	Test 1/1	3650-4107m	Gas with mud in 10hours

Ba-E1:

The Ba-E1 well was fracture-stimulated in two phases, initially during 2009 and then later in 2011. The initial completion comprised 2-stages in Zone C (one of which screened out). Both stages were limited entry targeting "clean gamma-ray" with gas shows (from mud log). Petrophysical analysis for these two zones have no areas that meet the net pay criteria. Flow-back gas rates peaked at 1.1 MMcf/D over a short 10-hour period.

The later completion in 2011 re-fractured the two former stages (described above) and added 2 up-hole stages (both Zone B). A total of 3m of net pay was completed. This most recent completion resulted in production to sales from a 3-stage completion; PLT logging confirmed contribution from all stages (Zones B and C). Favorable response to hydraulic stimulation demonstrates good geo-mechanical properties. Production data are not wholly reflective of likely commercial rates or volumes anticipated, with a large-scale completion targeting optimal pay.

Combined flowback peaked at 3.1 MMcf/D on a 10/64 choke, with 3,800psi WHP ~400 bbl/d natural gas liquids. API gravity of the natural gas liquids was 47 to 49°. The well was placed on long-term production testing in mid. 2011 and produced a cumulative <0.1 Bcf gas (~18 months). An average natural gas liquids yield of 170 bbl/MMcf is measured for the production period. A natural gas liquids yield of 120 bb/MMcf is used for the resource evaluation. No rate/time decline curve can be fitted to these data and no EUR was calculated. Gas analysis (Figure 11) shows rich gas with minor CO².

MOL NyRt. KTD Minőség és Technológia Ellenőrzés Sorszám: 771754
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VIZSGÁLATI JELENTÉS
FÖLDGÁZ ÖSSZETÉTEL

Vizsgáló laboratórium:	**Szank**
Mintavétel hely:	**Kiskunhalas Balota-É-1#**
Mintavétel időpontja:	**2011. 11. 21. 12:15:00**
Mintavételi hely nyomása:	**70** bar
Mintavételi hely hőmérséklete:	--- °C
Vizsgálat időpontja:	**2011. 11. 21.**

Komponens	mol %	g/m³
C_1	82,305	560,12
C_2	7,055	89,99
C_3	2,871	53,70
i-C_4	0,338	8,34
n-C_4	0,689	16,99
i-C_5	0,137	4,21
n-C_5	0,155	4,73
C_6	0,093	3,40
C_7	0,076	3,23
C_8	0,057	2,75
N_2 (+O_2)	0,255	3,03
CO_2	5,968	111,42
Összesen:	**100,000**	**861,91**

Számított adatok (MSZ ISO 6976 szerint):

Abszolút sűrűség (0 °C):	**0,9098** kg/m³	Relatív sűrűség (0 °C):	**0,7037**
Abszolút sűrűség (15 °C):	**0,8619** kg/m³	Relatív sűrűség (15 °C):	**0,7034**
Wobbe-szám (0 °C):	**51,23** MJ/m³	Fűtőérték (15 °C):	**36,77** MJ/m³
Wobbe-szám (15 °C):	**48,47** MJ/m³	Égéshő (15 °C):	**40,65** MJ/m³

Egyéb jellemzők:

$C_3 + C_4$ tartalom (15 °C):	**79,03** g/m³	CH harmatpont:	---
C_{5+} tartalom (15 °C):	**18,32** g/m³	Vízgőz harmatpont:	--- °C
Kénhidrogén tartalom:	**23,00** mg/m³	Vízgőz tartalom:	--- mg/m³
Oxigén tartalom:	--- mol%	Szagosítóanyag tartalom:	--- mg/m³
Szilárdanyagtartalom:	--- mg/m³	Összes kéntartalom:	--- mg/m³
Kritikus nyomás:	**47,6** bar	Kritikus hőmérséklet:	**-58,8** °C
"Z" tényező (15 °C, 101.325 kPa):	**0,9970**	CH harmatpont határérték:	**4,59** (4 MPa-on)

Figure 11. Produced gas analysis: Ba-E1

6. Contingent Resources

As defined in the COGE Handbook, Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Recognition as a known accumulation requires that the accumulation be penetrated by a well and have evidence of the existence of petroleum. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

Contingent Resources are further classified in accordance with the level of certainty associated with the estimates assuming their development and may be sub-classified based on project maturity. The Contingent Resources in this Report solely comprise of Development Unclarified Contingent Resources. Development Unclarified indicates that evaluation of the project is incomplete and there is activity required to resolve any risks or uncertainties regarding commercial development of the project. The Contingent Resources are sub-classified as Development Unclarified as development drilling is currently unscheduled.

The Development Unclarified, Contingent Resources in the Property are assigned based on previous well logs, well samples and production tests, in addition to legacy seismic data acquired on the Property. The estimates of Contingent Resources were prepared using volumetric methods. The input parameters for the evaluation are summarized in Table 4.

Table 4. Summary of Input Parameters

Zone A			
Input	Units	Best Est	Distribution Type
Gross Rock Area	Acre	7500	Calculated
Gross Thickness	ft	1050	Calculated
Net Pay	ft	23	Calculated
Porosity	%	8.5	Calculated
Water Saturation	%	29	Calculated
Formation Volume Factor	rcf/scf	0.0031	Calculated
Gas Recovery Factor	%	58	Calculated

Zone B			
Input	Units	Best Est	Distribution Type
Gross Rock Area	Acre	7500	Calculated
Gross Thickness	ft	900	Calculated
Net Pay	ft	85.3	Calculated
Porosity	%	6.5	Calculated
Water Saturation	%	33	Calculated
Formation Volume Factor	rcf/scf	0.003	Calculated
Gas Recovery Factor	%	63	Calculated

Zone C			
Input	Units	Best Est	Distribution Type
Gross Rock Area	Acre	7500	Calculated
Gross Thickness	ft	1200	Calculated
Net Pay	ft	105	Calculated
Porosity	%	12.5	Calculated
Water Saturation	%	22	Calculated
Formation Volume Factor	rcf/scf	0.0029	Calculated
Gas Recovery Factor	%	65	Calculated

Zone D			
Input	Units	Best Est	Distribution Type
Gross Rock Area	Acre	7500	Calculated
Gross Thickness	ft	1250	Calculated
Net Pay	ft	32.8	Calculated
Porosity	%	8	Calculated
Water Saturation	%	40	Calculated
Formation Volume Factor	rcf/scf	0.0028	Calculated
Gas Recovery Factor	%	58	Calculated

This Report does not include an economic evaluation of the Company's Contingent Resources.

6.1 Chance of Development

For Contingent Resources, the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development."

The following six factors were assessed for the Property in determining the chance of development:

- Economic Viability Factor: The most significant factor affecting the chance of development. The economic status of the project is undetermined and dependent on the results of the evaluation stage and most critically the price of gas and oil. The European market has seen rapid prices escalation due to recent political and environmental concerns. While the demand remains high, the volatility of gas and oil prices is a significant risk. Assigned a factor of 0.86.
- Market Access Factor: The Company does not anticipate any risk associated with market access. Assigned a factor of 1.
- Production and Transportation Infrastructure: Oil and gas related services are readily available in the region and infrastructure is favorable; however, as the project is still in the evaluation phase, a small risk is assigned to this factor. Assigned a factor of 0.95.
- Regulatory and Social License: As the government is supportive of exploration and production activities, no licensing issues are anticipated; however, as the project is still in the evaluation phase a small risk is assigned to this factor. Assigned a factor of 0.95.
- Corporate and External Approvals: No approval issues are anticipated; however, as the project is still in the evaluation phase a small risk is assigned to this factor. Assigned a factor of 0.95.
- Reasonable Timetable for Development: No timeline issues are anticipated; however, as the project is still in the evaluation phase a small risk is assigned to this factor. Assigned a factor of 0.98.

6.2 Risks and Significant Positive and Negative Factors

The major positive factor considered in determining estimates for the Contingent Resources is that a petroleum system has been confirmed in the Property, which includes organic rich, thermally mature source rock, stacked, low-permeability reservoir rock, effective top/lateral seals, trapping geometries/relations, favorable migration and preservation, and optimal timing of the above, all of which resulted in a large conventional natural gas/natural gas liquids accumulation.

The negative factors relevant to the estimates of Contingent Resources attributed to the Property are the discontinuity and heterogeneity of the target reservoir, uncertainty in seismically imaging structures (e.g. faults), and uncertainty in porosity and permeability estimates, and uncertainty in the fracability of the reservoir. Development will be strongly tied to the operator's ability to acquire high-resolution seismic data in order to high-grade and select well locations that maximize reservoir contact and minimize the impact of geohazards such as faults.

The significant risks associated with developing the Contingent Resources include:

- Gas prices: The European market has seen rapid price escalation due to political and environmental issues over the last 18 months, followed by more recent price stabilization. Any material drop in gas price below 11.00 Euros/MWh would potentially curtail the economics of development. Forward strip pricing for winter 2024/25 looks strong and is expected to rise from the 28.00 Euro/MWh average base level for Q1, 2024.
- Access to capital: Significant levels of future capital expenditure are required in order for the Contingent Resources to be recovered in the future.

- Reservoir conditions: The target reservoir is operationally challenging, being both high temperature and high pressure.
- Well performance: Individual well performance, as a function of initial rate and decline behavior will ultimately define the development drilling. Reservoir quality, thickness, and volume stimulated by hydraulic fracturing (i.e. the stimulated reservoir volume) will impact well performance.
- Producibility: The production potential of natural gas liquids and water and how they will impact the production of conventional natural gas are uncertain.

Additional risks include: regulatory approvals, access to the required services at the appropriate cost, and access to market.

6.3 Contingencies

The primary contingencies which prevent the classification of the resources at the Property as reserves are:

- The economic status is undetermined.
- The evaluation is incomplete and planned 3D seismic is necessary in addition to the data resulting from drilling and production testing.

As the Project is in the evaluation stage, more specific contingencies have not yet been clearly defined.

7. Recommended Work Program

The commercialization of the Kiskunhalas tight-gas project will be largely based upon results from any new well drilling ventures. A detailed work program (7.2, 7.3, 7.4 and 7.5) is recommended below in order to transition the contingent resource to a reserve classification. Existing legacy seismic data are of insufficient quality to specifically locate and design new drilling locations with an acceptable risk profile; therefore, a new 3D shoot was approved by the Company (section 7.1).

7.1 3D Seismic Acquisition (complete)

The Balotaszallas 3D seismic survey was permitted and funded in mid. 2023 and acquired throughout much of December 2023, for a cost of CA $2.55 million. The seismic field data was prepared, recorded and shipped to CanCambria in Q1, 2024 along with a report from AGS (contractor). The seismic survey is full azimuth, high density, with a maximum offset of 4,900m and 177-fold at the reservoir level. The survey was designed to provide an unparalleled image of the deep basin, leveraging two teams of 3 vibroseis trucks (each 60,000lbs). Figure 12 shows the survey outline and layout of source/receiver lines, spaced at 300m and 200m spacing respectively. After field testing, a single sweep of 22 seconds, from 2-110 hertz was found to be optimal. Several advanced processing tools and workflows will provide time and depth volumes, along with a determinist inversion.

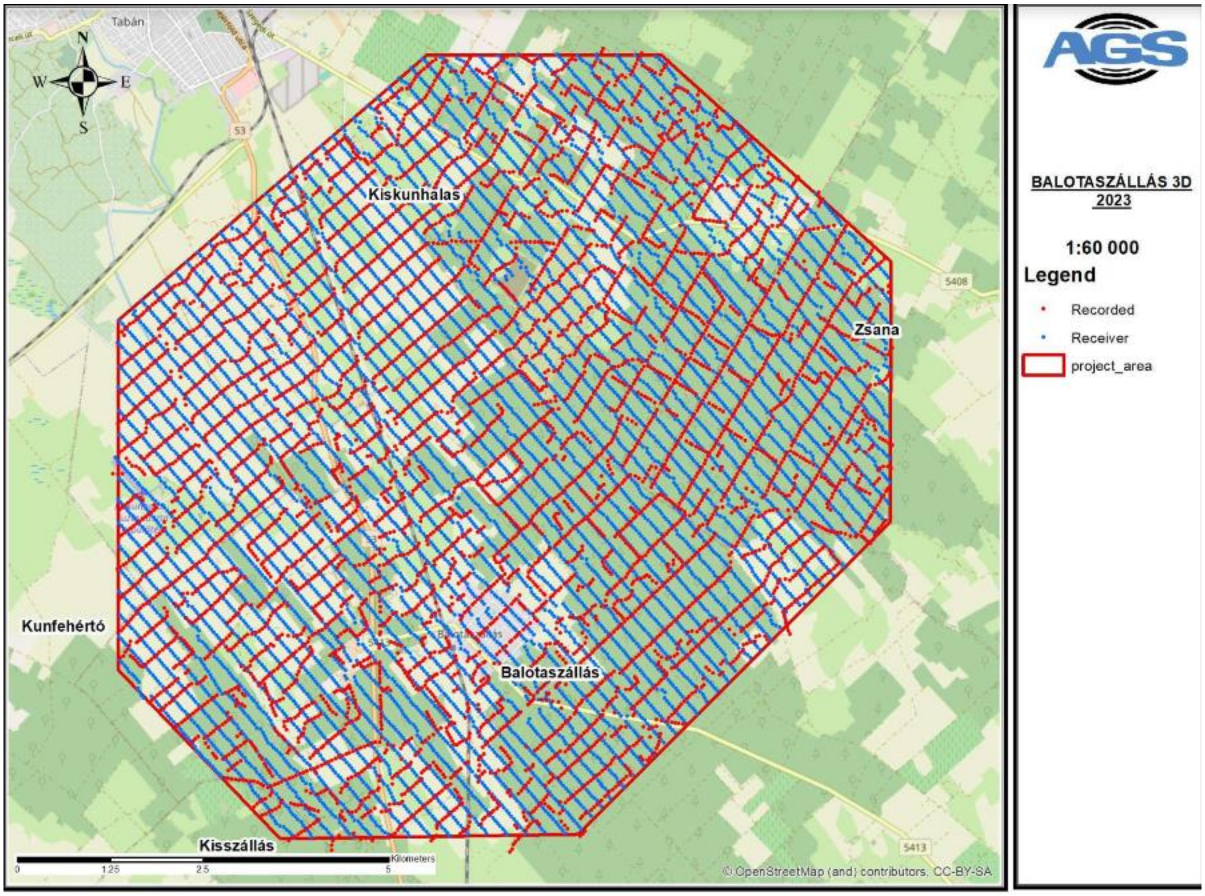

Figure 12. New 2023/24 Balotaszallas 3D survey with source/receiver lines

7.2 3D Seismic Processing and Petrophysical Modeling

Processing the 3D seismic with an established vendor, approximate timing of 6 months, at a cost of approx. CA $ 0.5 million. As of January 1st, the data was in transit to the processing shop in Houston, Texas. Key deliverables should include:

- Fastrack (QC) volume
- Time (PSTM) volume
- Depth (PSDM) volume
- Feasibility study AVO and fluid substitution
- Seismic Inversion volume – determinist (lithology and fluid types)
- Pore Pressure volume (based upon velocities)

7.3 3D Seismic Volume Interpretation and Integration

Engage with SMEs for full and comprehensive interpretation of all volumes prepared per section 7.2. Estimated duration for the recommended work plan is approximately 4 months at a cost of CA

$0.175 million. This part of the work program should include a range of technical exhibits based upon the interpretation of the new 3D, including but not limited to structural maps, attribute maps, and probability volumes. This scope of work will provide all technical and regulatory materials for the pre-drilling selection process and planning of the initial field appraisal well. Work products should include:

- Data QC and synthetic tie for the three key wells.
- Volume interpretation to include all key horizons and fault picks.
- Depth structure maps for all key formations (Zones A, B, C, D, Badenian and basement).
- Isopach (thickness) including Zones B and C (primary targets).
- Seismic attribute volumes (including coherence, dip, semblance).
- Lithology mapping and extraction (geo-bodies) from inversion.
- Rock quality maps – dependent upon modelling, may include porosity and fluid saturations.
- Structural model, fault polygons, and kinematic reconstruction.
- Integrate legacy well results and update geologic model.

Final deliverables from this interpretation work should include XY location(s) for optional appraisal well, to be provided to SMEs engaged in section 7.4

7.4 Engineering Design and Well Planning

Preparation of all materials supporting future drilling activity; starting Q4, 2024 with a duration of 9 months and costing CA $0.35 million. Consult/contract with SMEs experienced with drilling in the region. Wellbore stability, pore pressure, and mud system should be integrated for well design and casing program considerations. Application of the new 3D seismic volumes will also assist in geohazard detection, in addition to ranking drilling locations. No tangible or intangible well-related costs are included in the phase. It is recommended the company engage with service companies and vendors directly to prepare best practices for key consideration including:

- Offset well analysis – well events
- Geologic prognosis (to include location) – formation tops and TD
- Mud system and pore pressure
- Casing design / program
- Well-head design
- Formation evaluation
- Completion design
- Surveillance and monitoring
- Flow back protocol and water disposal
- Gas sales and pipeline
- Abandonment
- HSE and emergency plan

7.5 Drilling, Completion and Production of New Well

Contingent upon the above work program, a new well may be permitted and drilled no sooner than 2H, 2025 – costs TBD. Many long lead items will need to be sourced. HSE and regulations to be compliant.

8. Development Plan

No development plan has been prepared at this stage of the project and no economic model has been run. Any such field development plan will be based upon the results of the Section 7 work program and production performance (and analytics) from new drill wells.

Abbreviations

3D:	three dimensional
AFE:	authority for expense
API:	American Petroleum Institute
AVO:	amplitude verses offset
Bbl:	barrel
Bcf:	Billion cubic feet
BOE:	barrel oil equivalent
C1:	Methane
C2:	Ethane
C3:	Propane
CA$:	Canadian dollar
QC:	quality control
CGG:	www.cgg.com (service company)
COGE:	Canadian Oil & Gas Evaluation
CO_2:	Carbon Dioxide
DGIIP:	Discovered gas initially in place
DST:	drill stem test
E&P:	exploration and production
E:	east
EUR:	estimated ultimate recovery
Fm:	formation
Ft:	feet
HTHP:	high-temperature high-pressure
HC:	hydrocarbon
HSE:	health, safety, and environment
km:	kilometer
lbs:	pounds
m:	meter
Md:	millidarcy
MMcf/D:	Million cubic feet per day
MMcf:	Million cubic feet
MWh:	megawatt hour
N:	north
NRI:	net revenue interest
OGIP:	original gas in place
Q:	quarter (business)
PLT:	Production temperature log
PSTM:	pre-stack time migration
PSDM:	pre-stack depth migration
Rcf:	reservoir cubic feet
Ro:	Vitrinite reflectance
S:	south
Scf:	surface cubic feet
SME:	subject matter expert
Sw:	water saturation
TD:	total depth
TBD:	to be determined
TOC:	total organic carbon
TVD:	true vertical depth
VSP:	vertical seismic profile
W:	west
WI:	working interest
WHP:	well head pressure
%:	percentage
°C:	degree Celsius