August 28, 2010

British Columbia Oil and Gas Commission
Resource Conservation Branch
PO Box 9329 Stn Prov Gov't
Victoria, BC V8W 9N3

ATTENTION: DIRECTOR OF THE RESOURCE CONSERVATION BRANCH

Richard Slocomb:

APPLICATION FOR APPROVAL OF A GOOD ENGINEERING PRACTICE AREA FOR THE PRODUCTION OF GAS FROM THE JEAN MARIE FORMATION IN THE PICKELL FIELD

NOTIFICATION

Yoho Resources Partnership (Yoho) and its partner, Aspect Energy Partnership (Aspect) have undertaken pre-notification of this application to all potentially affected parties, with offset mineral rights in the surrounding twenty five, Normal Spacing Areas (NSA's) of 4 units each for gas.

A notification letter regarding the proposed application has been sent to offset Jean Marie mineral interest holders (Exhibit 2) on Sept 1st, 2010. Accordingly, Yoho and Aspect request that the OGC proceed with the processing of this application. A sample copy of the notification letter and listings of addressees are included in Exhibit 4 of this application.

Yoho Resources Partnership and Aspect Energy Partnership, hereby submit this application for approval of a Good Engineering Practice (GEP) area, for the production of Jean Marie in the Pickell Field. The application area is shown in Exhibit 1.

This application is made pursuant to Section 101 of the Drilling and Production Regulations and the information herein is provided as per OGC Guidelines (12.7) for an application for approval of a Good Engineering Practice Area on the following lands (see Exhibit 2):

094-H-02, Blk E, Units 34-39, 44-49, 56-60, 66-70, 82-86, and 94-100,

094-H-02, Blk L, Units 4-10, 14, 15, 18-20, 24, 25, 28-30, 40, 50, 56-60, 66-70, 78-79, and 88-89
094-H-03, Blk H, Units 34,-35, 44-45, 51-55, 61-65, 71-75, 81-85, and 91-93
094-H-03, Blk I, Units 1-3, 11-13, 21-23, 31-33, 41-43, 51-53, 61-63, 72-73, and 82-83

GENERAL DISCUSSION

The application for a GEP area for the production of Jean Marie gas is based upon the following:

- Yoho and Aspect believe that the approval for a GEP area will improve the efficiency of delineation, development and depletion of the resource while increasing gas recoveries from the on the subject lands.
- There are no anticipated equity issues.

The area of application is presently subject to the default 4 units NSA, central target area in accordance with section 10(2) of the Drilling and Production Regulations. Within the application area, Yoho and Aspect is requesting to have a well density of at least 4 wells per NSA for the production of Jean Marie gas.

Currently, Jean Marie production is limited to vertical producers A-19-L/94-H-2 and C-8-L/94-H-2 in the application area. Decline analysis was performed on both wells and initial gas in place was calculated using pool and well parameters. A comparison of these values was performed to determine a recovery factor and drainage area for each well (Exhibit 3).

The calculated recovery factors and drainage areas of these Jean Marie wells, illustrate that they will not drain an entire NSA. An increased well density will optimize production of the Jean Marie gas reserves in this area.

There is no GEP precedence for Jean Marie gas within the subject Fields. However, numerous GEP approvals have been granted for the same formation in the Helmet, Sierra, Tsea, Cabin, Elleh, Bivouac, and Ekwan areas. Yoho and Aspect wishes a similar opportunity to develop Jean Marie gas on the application lands.

Yoho and Aspect believes that with the reservoir heterogeneity and limited “effective” drainage areas, for reasons outlined in this application, several wells in the default gas

NSA is necessary to allow the most efficient delineation, development, and depletion of the Jean Marie formation. Yoho and Aspect's request to have increased well density will also enable economic development.

Note: The results of the decline analysis referenced in this application (see Exhibit 3), summarizes the producing formations/pool, initial gas in place, recoverable reserves, recovery factor, drainage area, remaining recoverable reserves and the remaining reserves life index. The original gas in place (OGIP) estimate is determined from BC Gas Pool Records along with individual well petrophysical parameters from zone evaluations given on the well tickets and based on the well default NSA (4 Units) of an approximate area of 281 ha. The fractional recovery factor is the projected total gas produced at abandonment, divided by the OGIP. The drainage area is subsequently derived from the product of the recovery factor and the default gas NSA area.

GEOLOGY DISCUSSION

Jean Marie is a Upper Devonian age carbonate present over a large portion of the WCSB, particular north and west of the Peace River Arch. Underlying the Jean Marie are the thick shales (approx. 350m) of the Fort Simpson. The boundary is marked by a sharp drop in the gamma ray curve (see Exhibit 4). The basal part of the Jean Marie is a skeletal-rich unit, typically a few metres thick, that marks a reworked surface during an overall transgression. The Redknife Formation overlies the Jean Marie and the sharp boundary is marked by the presence of a 1 to 2m shale (see Exhibit 4).

The Jean Marie reservoir in the Pickell area was deposited on a broad marine platform that deepens to the west-northwest into a shale basin, namely the Horn River Basin and Cordova Embayment (see Exhibit 4). Lithofacies vary from nodular lime mudstones to coral-rich floatstones/grainstones and platy/wafer stromatoporoid rudstones (see Exhibit 4). These core rich floatstones and stromatoporoid rudstones form reefs/mounds that are the reservoir units in the Jean Marie. In the Pickell area, the platy stromatoporoids are almost exclusively the reservoir facies. All lithofacies appear to be deposited in an open marine setting. Based on our interpretation, the reservoir facies forms a series of "mounds" that appear to trend NW-SE.

The Jean Marie is a leached limestone reservoir (see Exhibit 4) with dolomitization present in only minor (i.e. <5%) to trace amounts (see Exhibit 4). Thicknesses are approximately 15m and are similar to those found in the Helmet pools to the north. Pore types are primarily: microfracture, shelter (platy stromatoporoids), vuggy and moldic. Overall porosity varies from 1 to as high as 10% (see Exhibit 4). Permeability is also variable, but is generally interpreted to be <1mD (Exhibit 4; NOTE: permeability analysis is often is unreliable due to fractured nature of core). Those portions with density porosity greater 3% generally have permeability <0.01mD, and likely contribute minimally to overall production with current completed wells (i.e. perforation and acid squeeze). However, the entire interval appears to be gas saturated (see Exhibit 4) and it is partly for this reason that Yoho and Aspect contends that the Jean Marie requires enhanced recovery techniques (i.e. multiple horizontals per spacing unit, hydraulic fracturing) to recover more of the gas.

EQUITY

There should be minimal adverse correlative rights impacts resulting from the approval of this application. Strategic placement of well(s) under GEP should provide against off-lease drainage of offset equity.

Yoho and Aspect are the mineral interest holders and working interest participants in the application area as shown in the land data summary of Exhibit 2. A copy of the pooling agreement executed between Yoho and Aspect is available upon request.

SUPPORTING DOCUMENTATION

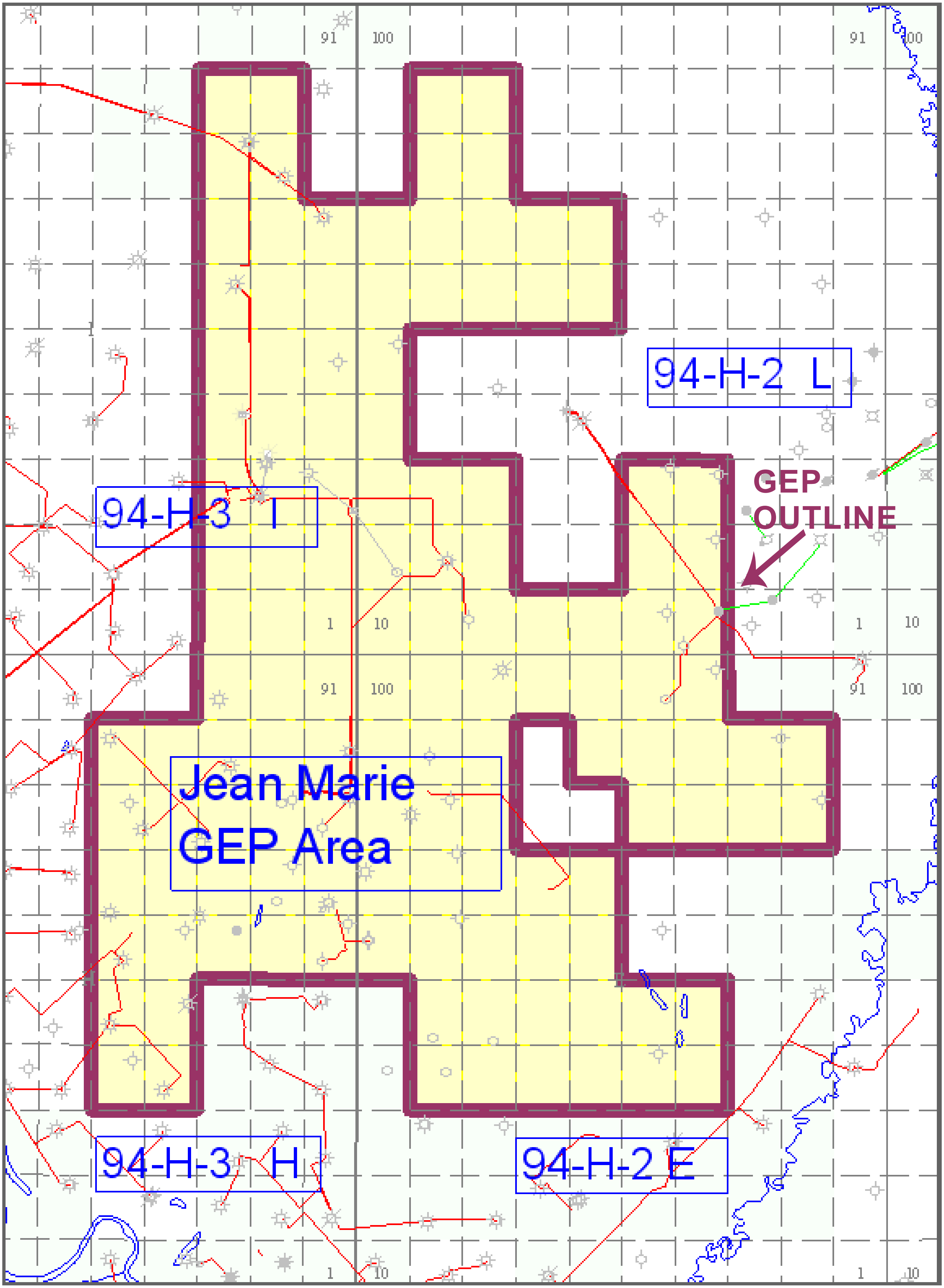
In accordance with OGC Section 101 and Guidelines 12.7, we hereby include the following Exhibits in support of the application.

Exhibit 1	Application Area Map
Exhibit 2	Lessor/Lessee Maps, Land Data Summary and Well Status Summary
Exhibit 3	Jean Marie engineering data: reservoir parameters, decline analysis
Exhibit 4	Sample Notification Letter and List of Addresses
Exhibit 5	Jean Marie Geologic data: regional maps, logs, XRD, thin section, core analysis, core descriptions

We trust this application meets with your approval and would appreciate your earliest attention to this matter. If you have any questions or concerns regarding the application, please contact Barry Stobo at 403-537-1771 ext 104 or Kevin Fossenier at ext 106.

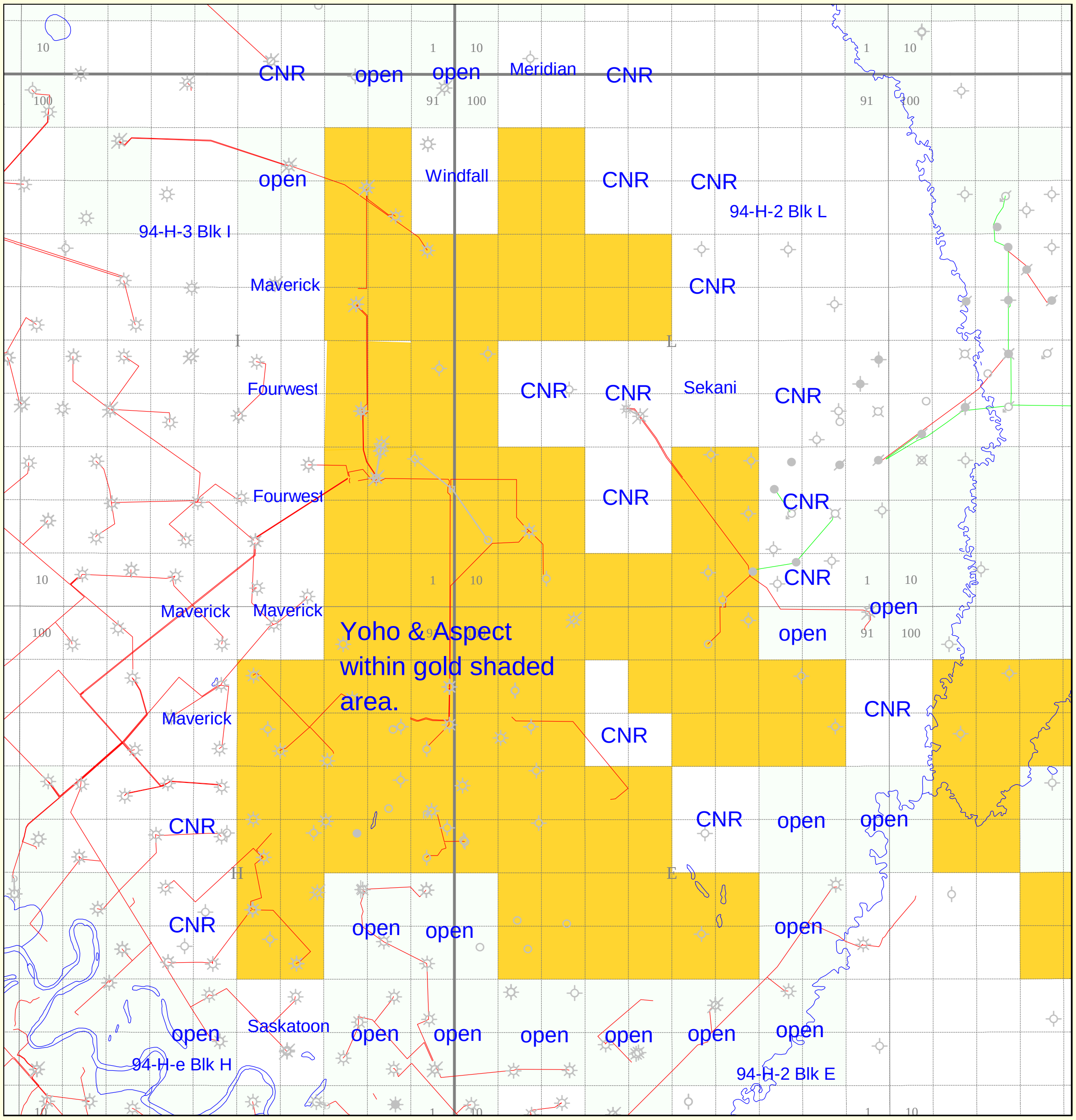
Yours truly, **Yoho Resources Inc.**	Yours truly, **Yoho Resources Inc.**
Barry Stobo, P.Eng VP Engineering, COO	Kevin Fossenier, P.Geol. Senior Explorationist

EXHIBIT 1 **APPLICATION AREA MAP**



91
100
91
100
94-H-2 L
GEP OUTLINE
94-H-3 I
1
10
1
10
91
100
91
100
Jean Marie GEP Area
94-H-3 H
94-H-2 E
1
10
1
10

EXHIBIT 2 LESSOR/LESSEE MAPS, LAND DATA SUMMARY AND WELL STATUS SUMMARY



Map Center on: D-9-L/94-H-2

WELL LEGEND

Bottom Hole Locations:

○	Location	⌽	Suspended
⌑	Service or Drain	●	Oil
☼	Gas	⌖	Dry & Abandoned
●	Suspended Oil	✦	Abandoned Oil
☼	Suspended Gas	✳	Abandoned Gas
⊠	Abandoned Service	○	Injection

PROPRIETARY DATA LEGEND

Regions:

🟧	CANOIL
🟨	YOHO DLS
🟨	YOHO NTS

Yoho Resources Inc

Pickell Field BC
Lessors/Lessees Jean Marie

Created in AccuMap™
Product of IHS
Datum: NAD83

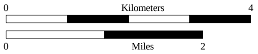
Vol. 20 No. 08, Aug 17 2010
(403) 770-4646

Author: CWD
Date: August 27, 2010
File: GEP map on Lessors -Pickell.MA
Scale: 1 : 98436
Projection: Stereographic
Center: N57.17389 W120.97751

Grid Information:
DLS: IHS Enhanced Grid
NTS: Theoretical Grid
FPS: Theoretical Grid
US: IHS US Grid

DLS Version Information:
AB: ATS 4.1
BC: PRB 2.0
SK: STS 2.5
MB: MLI07

Scale 1:98436



PICKELL FIELD, BC
MINERALS LAND DATA SUMMARY

Location	Lessor	Lessee	Interest	Rights
Inside Application Area				
94-H-2 Blk E Units 34-39, 44-49, 56-60, 66-70, 72-75, 78-80, 82-86, 94-100	CROWN	Yoho Resources Inc	84.80%	P&NG in the Jean Marie
		Aspect Energy Partnership	15.20%	
94-H-2 Blk L Units 4-10,14,15,18-20,24,25,28-30,40,50,56-60,66-70,78,79,88,89	CROWN	Yoho Resources Inc	84.80%	P&NG in the Jean Marie
		Aspect Energy Partnership	15.20%	
94-H-3 Blk H Units 34,35,44,45,51-55,61-65,71-75,81-85,91-93	CROWN	Yoho Resources Inc	84.80%	P&NG in the Jean Marie
		Aspect Energy Partnership	15.20%	
94-H-3 Blk I Units 1-3,11-13,21-23,31-33,41-43,51-53,61-63,72,73,82,83	CROWN	Yoho Resources Inc	84.80%	P&NG in the Jean Marie
		Aspect Energy Partnership	15.20%	
Outside Application Area				
94-H-2 Blk E 12-20,22-30,32,33,42,43,52,53,62,63,71,81,91-93	CROWN	Open	100%	P&NG in the Jean Marie
94-H-2 Blk E 76,77,87	CROWN	Canadian Natural Resources Limited	100%	P&NG in the Jean Marie
94-H-2 Blk L 100	CROWN	Open	100%	P&NG in the Jean Marie
94-H-2 Blk L 2,3,12,13,16,17,22,23,26,27,32,33,36-39,42,43,46-49,54,55,64,65,	CROWN	Canadian Natural Resources Limited	100%	P&NG in the Jean Marie
74-77,84-87,96,97				
94-H-2 Blk L 34,35,44,45	CROWN	Sekani Resources Ltd	100%	P&NG in the Jean Marie
94-H-2 Blk L 80,90	CROWN	Windfall Resources Ltd	100%	P&NG in the Jean Marie
94-H-2 Blk L 98,99	CROWN	Meridian Land Services Ltd	100%	P&NG in the Jean Marie
94-H-3 Blk H 11-17,21-27,31-33,41-43	CROWN	Open	100%	P&NG in the Jean Marie
94-H-3 Blk H 14,15,24,25	CROWN	Saskatoon Assets Ltd	100%	P&NG in the Jean Marie
94-H-3 Blk H 36,37,46,47,56,57,66,67	CROWN	Canadian Natural Resources Limited	100%	P&NG in the Jean Marie
94-H-3 Blk H 76,77,86,87,94-97	CROWN	Maverick Land Consultants Inc	100%	P&NG in the Jean Marie
94-H-3 Blk I 4-7, 54,55,64,65	CROWN	Maverick Land Consultants Inc	100%	P&NG in the Jean Marie
94-H-3 Blk I 14,15,24,25,34,35,44,45	CROWN	Four West Land Consultants Ltd	100%	P&NG in the Jean Marie
94-H-3 Blk I 74,75,84,85	CROWN	Open	100%	P&NG in the Jean Marie
94-H-3 Blk I 71,81	CROWN	Windfall Resources Ltd	1005%	P&NG in the Jean Marie
94-H-3 Blk I 94,95	CROWN	Canadian Natural Resources Limited	100%	P&NG in the Jean Marie
H/GEP Application Jean Marie				

EXHIBIT 3 JEAN MARIE: ENGINEERING DATA

ESTIMATE OF GAS RESERVES

Area: Pickell
Well: A-19-L-94-H-2
Pool Zone: Jean Marie

RESERVOIR PARAMETERS

Top of Gross Pay	2448	m	8031.5	ft
Base of Gross Pay	2463	m	8080.7	ft
Gas/Oil or Gas/Water contact	N/A	m		ft
Porosity		5.4%		5.4%
Initial Water Saturation		20%		20%
Residual Oil Saturation		0%		0%
Initial Reservoir Pressure		37452kpa		5,432psi
Reservoir Temperature		100 °C		212 °F
Compressibility Factor		1.061		1.061
Productive Area		32ha		80acres
Average Net Pay		12.5m		41ft
Recovery Factor		70%		70%
Surface Loss		7%		7%
Initial Raw GIP	46.5	10^6m^3	1650	Mmcf
Initial Recoverable Raw GIP	32.8	10^6m^3	1165	Mmcf
Initial Marketable GIP	30.5	10^6m^3	1084	Mmcf
Cum Raw Production	14.7	10^6m^3	521	Mmcf
Cum Sales Prod. To	13.6	10^6m^3	484	Mmcf
Remaining Marketable GIP	16.9	10^6m^3	599	Mmcf

Gas Gravity	0.561		0.561	
N2 Concentration	0.92	%	0.92	%
CO2 Concentration	1.18	%	1.18	%
H2S Concentration	0.0	%	0.0	%
Critical Pressure	4620	kpa	670	psi
Critical Temperature	192	°K	345.6	°R
Gross Heating Value	37.64	MJ/m^3	1005	BTU/scf

(default company)

Technical Reserves at September 1, 2010

200/a-019-L/094-H-02/2 (Working Copy, Raw)

Field / Pool	Other Areas / Kotcho
Lithology	

Reservoir Volumetric Values		**PDP**	**PNP**	**PUD**	**P+PDP**	**P+PNP**	**P+PUD**
KB Elevation	ft						
Formation Top (KB)	ft						
Formation Bottom (KB)	ft						
Gross Pay	ft						
Gross Rock Volume	Ac·ft						
Gross Pore Volume	Ac·ft						
Gas Hydrocarbon PV	Ac·ft						
OGIP / Gross Rock Vol.	Mcf/(Ac·ft)						
Pool Area	Ac						
Current Pressure	psia						
Productive Area (A)	Ac						
Net Pay (h)	ft						
Porosity (Phi)	%						
Phi*h	ft						
Water Saturation (Sw)	%						
Oil Saturation (So)	%						
Gas Saturation (Sg)	%						
Initial Pressure	psia						
Reservoir Temperature	°F						
Z Factor							
Bg (Gas Form. Vol. Factor)							
Material Balance Factors							
Pi	psia						
PAbandon	psia						
Gross Technical Reserves							
Orig. Gas In Place	MMcf						
Recovery Factor	%						
Orig. Rec. Raw Gas In Place	MMcf	1,165.2					
Cum. Prod. through Aug 2010	MMcf	520.7					
Rem. Rec. Raw Gas In Place	MMcf	644.5					
Total Gas Loss	%	7.00					
Orig. Rec. Sales Gas In Place	MMcf	1,083.7					
Cum. Sales through Aug 2010	MMcf	484.3					
Rem. Rec. Sales Gas In Place	MMcf	599.4					
Start of Forecast		Jul 1, 2010					
Cum. Prod. up to Fcst. Start	MMcf	505.6					
Based On		**Dec. Analysis**					

Declines

Segment	**Res Cat**	**Date**	**Qi**	**Di (Nom)**	**Ni**	**Max**	**Qf**
Gas 1	PDP	Jun 2010	247.7 Mcf/d	0.123306 #/yr	0.0000	582.9 Mcf/d	25.0 Mcf/d

(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
200/a-019-L/094-H-02/2 (Working Copy, Raw)

Date	Wells	CDOR	Cum Oil	CDGR	Cum Gas	CDBOE	Cum BOE	CDWR	Cum Water	OGR	FGR	Hours
		(bbl/d)	(Mbbl)	(Mcf/d)	(MMcf)	(bbl/d)	(Mbbl)	(bbl/d)	(Mbbl)	(bbl/MMcf)	(bbl/MMcf)	(hr)
Mar 2006	1.00	0.0	0	325.2	10	54.2	2	0.0	0	0.0	0.0	300
Apr 2006	1.00	0.0	0	701.8	31	117.0	5	0.0	0	0.0	0.0	667
May 2006	1.00	0.0	0	256.8	39	42.8	7	0.0	0	0.0	0.0	370
Jun 2006	1.00	0.0	0	608.2	57	101.4	10	0.0	0	0.0	0.0	646
Jul 2006	1.00	0.0	0	466.9	72	77.8	12	0.0	0	0.0	0.0	744
Aug 2006	1.00	0.0	0	427.0	85	71.2	14	0.0	0	0.0	0.0	739
Sep 2006	1.00	0.0	0	361.7	96	60.3	16	0.0	0	0.0	0.0	612
Oct 2006	1.00	0.0	0	396.4	108	66.1	18	0.0	0	0.0	0.0	641
Nov 2006	1.00	0.0	0	391.0	120	65.2	20	0.0	0	0.0	0.0	696
Dec 2006	1.00	0.0	0	365.0	131	60.8	22	0.0	0	0.0	0.0	660
Jan 2007	1.00	0.0	0	368.2	143	61.4	24	0.0	0	0.0	0.0	722
Feb 2007	1.00	0.0	0	325.0	152	54.2	25	0.0	0	0.0	0.0	607
Mar 2007	1.00	0.0	0	345.9	162	57.6	27	0.0	0	0.0	0.0	696
Apr 2007	1.00	0.0	0	358.4	173	59.7	29	0.0	0	0.0	0.0	720
May 2007	1.00	0.0	0	344.5	184	57.4	31	0.0	0	0.0	0.0	727
Jun 2007	1.00	0.0	0	338.0	194	56.3	32	0.0	0	0.0	0.0	720
Jul 2007	1.00	0.0	0	329.7	204	55.0	34	0.0	0	0.0	0.0	722
Aug 2007	1.00	0.0	0	310.7	214	51.8	36	0.0	0	0.0	0.0	672
Sep 2007	1.00	0.0	0	340.0	224	56.7	37	0.0	0	0.0	0.0	638
Oct 2007	1.00	0.0	0	325.3	234	54.2	39	0.0	0	0.0	0.0	742
Nov 2007	1.00	0.0	0	311.5	244	51.9	41	0.0	0	0.0	0.0	655
Dec 2007	1.00	0.0	0	295.3	253	49.2	42	0.0	0	0.0	0.0	672
Jan 2008	1.00	0.0	0	311.1	262	51.8	44	0.0	0	0.0	0.0	655
Feb 2008	1.00	0.0	0	288.6	271	48.1	45	0.0	0	0.0	0.0	696
Mar 2008	1.00	0.0	0	282.8	279	47.1	47	0.0	0	0.0	0.0	720
Apr 2008	1.00	0.0	0	326.0	289	54.3	48	0.0	0	0.0	0.0	694
May 2008	1.00	0.0	0	289.1	298	48.2	50	0.0	0	0.0	0.0	720
Jun 2008	1.00	0.0	0	46.7	300	7.8	50	0.0	0	0.0	0.0	168
Jul 2008	1.00	0.0	0	388.7	312	64.8	52	0.0	0	0.0	0.0	574
Aug 2008	1.00	0.0	0	363.0	323	60.5	54	0.0	0	0.0	0.0	744
Sep 2008	1.00	0.0	0	339.3	333	56.6	56	0.0	0	0.0	0.0	720
Oct 2008	1.00	0.0	0	311.1	343	51.8	57	0.0	0	0.0	0.0	744
Nov 2008	1.00	0.0	0	281.5	351	46.9	59	0.0	0	0.0	0.0	672
Dec 2008	1.00	0.0	0	229.3	358	38.2	60	0.0	0	0.0	0.0	744
Jan 2009	1.00	0.0	0	348.4	369	58.1	62	0.0	0	0.0	0.0	744
Feb 2009	1.00	0.0	0	292.8	377	48.8	63	0.0	0	0.0	0.0	672
Mar 2009	1.00	0.0	0	275.4	386	45.9	64	0.0	0	0.0	0.0	744
Apr 2009	1.00	0.0	0	272.9	394	45.5	66	0.1	0	0.0	0.3	720
May 2009	1.00	0.0	0	271.2	402	45.2	67	0.0	0	0.0	0.0	744
Jun 2009	1.00	0.0	0	270.6	411	45.1	68	0.0	0	0.0	0.0	720
Jul 2009	1.00	0.0	0	268.1	419	44.7	70	0.0	0	0.0	0.0	744
Aug 2009	1.00	0.0	0	254.4	427	42.4	71	0.0	0	0.0	0.0	696
Sep 2009	1.00	0.0	0	270.2	435	45.0	72	0.0	0	0.0	0.0	720
Oct 2009	1.00	0.0	0	265.5	443	44.3	74	0.0	0	0.0	0.0	744
Nov 2009	1.00	0.0	0	282.1	452	47.0	75	0.0	0	0.0	0.0	720
Dec 2009	1.00	0.0	0	258.8	460	43.1	77	0.0	0	0.0	0.0	744
Jan 2010	1.00	0.0	0	261.2	468	43.5	78	0.0	0	0.0	0.0	744
Feb 2010	1.00	0.0	0	259.5	475	43.2	79	0.0	0	0.0	0.0	672
Mar 2010	1.00	0.0	0	248.3	483	41.4	80	0.0	0	0.0	0.0	720
Apr 2010	1.00	0.0	0	252.7	490	42.1	82	0.0	0	0.0	0.0	720
May 2010	1.00	0.0	0	253.0	498	42.2	83	0.0	0	0.0	0.0	744
Jun 2010	**1.00**	**0.0**	**0**	**251.9**	**506**	**42.0**	**84**	**0.0**	**0**	**0.0**	**0.0**	**720**
Jul 2010	1.00	0.0	0	245.1	513	40.8	86	0.0	0	0.0	0.0	740
Aug 2010	1.00	0.0	0	242.5	521	40.4	87	0.0	0	0.0	0.0	740
Sep 2010	1.00	0.0	0	240.1	528	40.0	88	0.0	0	0.0	0.0	716
Oct 2010	1.00	0.0	0	237.6	535	39.6	89	0.0	0	0.0	0.0	740
Nov 2010	1.00	0.0	0	235.2	542	39.2	90	0.0	0	0.0	0.0	716
Dec 2010	1.00	0.0	0	232.8	550	38.8	92	0.0	0	0.0	0.0	740
Jan 2011	1.00	0.0	0	230.4	557	38.4	93	0.0	0	0.0	0.0	740
Feb 2011	1.00	0.0	0	228.1	563	38.0	94	0.0	0	0.0	0.0	668
Mar 2011	1.00	0.0	0	225.9	570	37.6	95	0.0	0	0.0	0.0	740

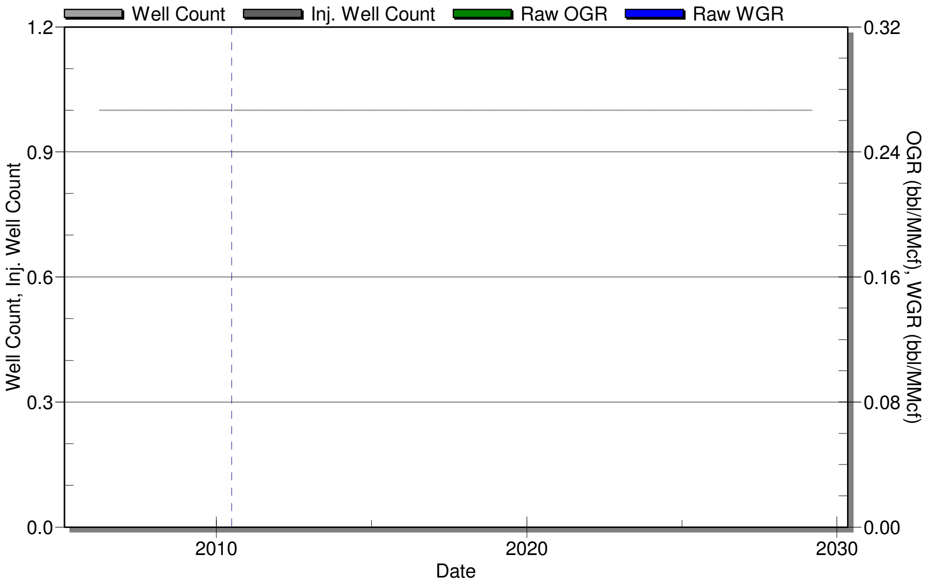
(default company)

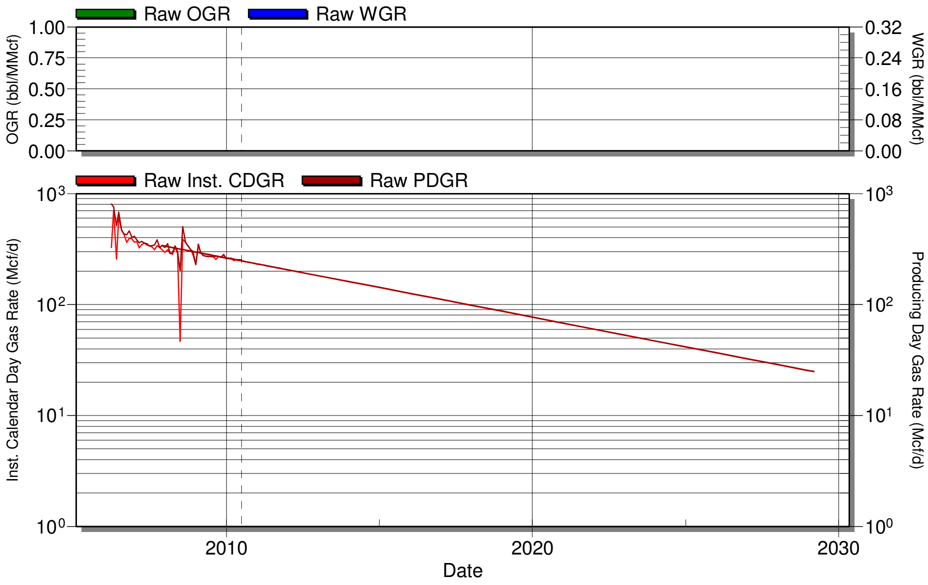
Technical Reserves at September 1, 2010
Proved Developed Producing
200/a-019-L/094-H-02/2 (Working Copy, Raw)

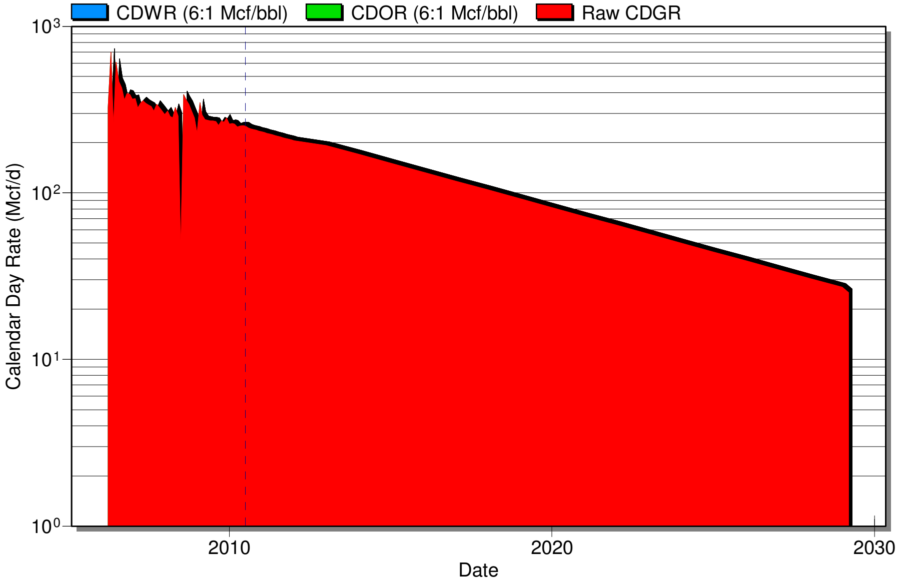
Date	Wells	CDOR (bbl/d)	Cum Oil (Mbbl)	CDGR (Mcf/d)	Cum Gas (MMcf)	CDBOE (bbl/d)	Cum BOE (Mbbl)	CDWR (bbl/d)	Cum Water (Mbbl)	OGR (bbl/MMcf)	FGR (bbl/MMcf)	Hours (hr)
Apr 2011	1.00	0.0	0	223.6	577	37.3	96	0.0	0	0.0	0.0	716
May 2011	1.00	0.0	0	221.3	584	36.9	97	0.0	0	0.0	0.0	740
Jun 2011	1.00	0.0	0	219.0	590	36.5	98	0.0	0	0.0	0.0	716
Jul 2011	1.00	0.0	0	216.8	597	36.1	99	0.0	0	0.0	0.0	740
Aug 2011	1.00	0.0	0	214.6	604	35.8	101	0.0	0	0.0	0.0	740
Sep 2011	1.00	0.0	0	212.4	610	35.4	102	0.0	0	0.0	0.0	716
Oct 2011	1.00	0.0	0	210.2	616	35.0	103	0.0	0	0.0	0.0	740
Nov 2011	1.00	0.0	0	208.1	623	34.7	104	0.0	0	0.0	0.0	716
Dec 2011	1.00	0.0	0	206.0	629	34.3	105	0.0	0	0.0	0.0	740
Dec 2012	1.00	0.0	0	192.8	700	32.1	117	0.0	0	0.0	0.0	8,737
Dec 2013	1.00	0.0	0	170.5	762	28.4	127	0.0	0	0.0	0.0	8,713
Dec 2014	1.00	0.0	0	150.9	817	25.1	136	0.0	0	0.0	0.0	8,713
Dec 2015	1.00	0.0	0	133.5	866	22.2	144	0.0	0	0.0	0.0	8,713
Dec 2016	1.00	0.0	0	118.0	909	19.7	151	0.0	0	0.0	0.0	8,737
Dec 2017	1.00	0.0	0	104.4	947	17.4	158	0.0	0	0.0	0.0	8,713
Dec 2018	1.00	0.0	0	92.4	981	15.4	163	0.0	0	0.0	0.0	8,713
Dec 2019	1.00	0.0	0	81.7	1,011	13.6	168	0.0	0	0.0	0.0	8,713
Dec 2020	1.00	0.0	0	72.3	1,037	12.0	173	0.0	0	0.0	0.0	8,737
Dec 2021	1.00	0.0	0	63.9	1,060	10.7	177	0.0	0	0.0	0.0	8,713
Dec 2022	1.00	0.0	0	56.6	1,081	9.4	180	0.0	0	0.0	0.0	8,713
Dec 2023	1.00	0.0	0	50.0	1,099	8.3	183	0.0	0	0.0	0.0	8,713
Dec 2024	1.00	0.0	0	44.3	1,115	7.4	186	0.0	0	0.0	0.0	8,737
Dec 2025	1.00	0.0	0	39.1	1,130	6.5	188	0.0	0	0.0	0.0	8,713
Dec 2026	1.00	0.0	0	34.6	1,142	5.8	190	0.0	0	0.0	0.0	8,713
Dec 2027	1.00	0.0	0	30.6	1,154	5.1	192	0.0	0	0.0	0.0	8,713
Dec 2028	1.00	0.0	0	27.1	1,163	4.5	194	0.0	0	0.0	0.0	8,737
Dec 2029	1.00	0.0	0	25.2	1,165	4.2	194	0.0	0	0.0	0.0	1,688

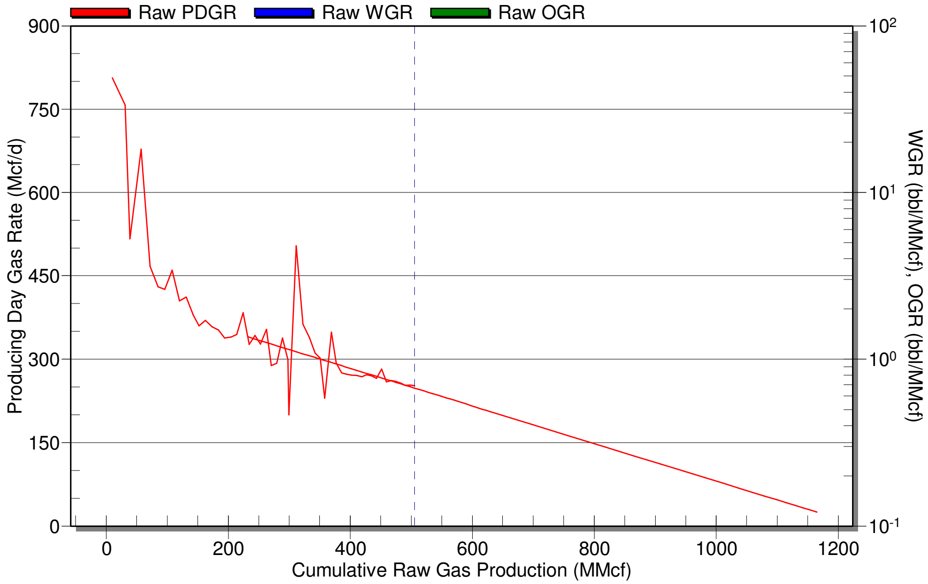
(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
200/a-019-L/094-H-02/2 (Working Copy, Raw)









(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
200/a-019-L/094-H-02/2 (Working Copy, Raw)

Status	Producer:	**Aprox. On-time**	99.46%
Field	Other Areas	**Rig Release**	Feb 2005
Pool	Kotcho	**WI**	100.00%
Unit	N/A	**RLI**	7.4
Operator	YOHO RESOURCES INC.	**Type**	PDP
Licensee			Raw

Technical Reserves at Sep 1, 2010 (Based on Dec. Analysis)

	Ultimate Reserves	Cumulative Production	Remaining Gross	Remaining WI
Oil (Mbbl)	0.0	0.0	0.0	0.0
Gas (MMcf)	1,165.2	520.7	644.5	644.5
Water (Mbbl)	0.0	0.0	0.0	0.0

Declines

Segment	Start Date	Qi*	Di** (Nom)	Ni	Max***	Qf*
Gas 1	Jun 2010	247.7	0.123306	0.00	582.9	25.0

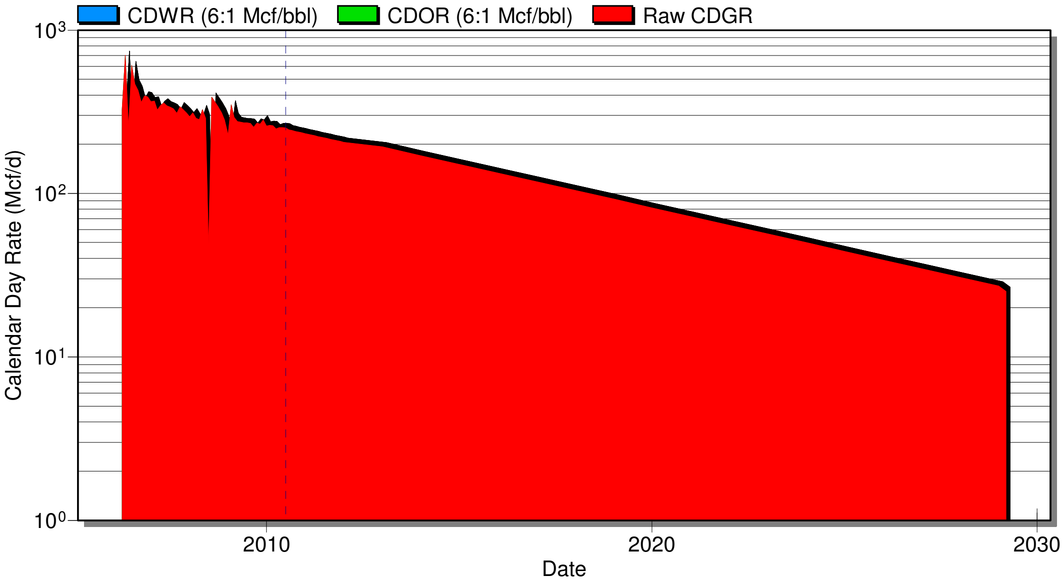
*Qi, Qf units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

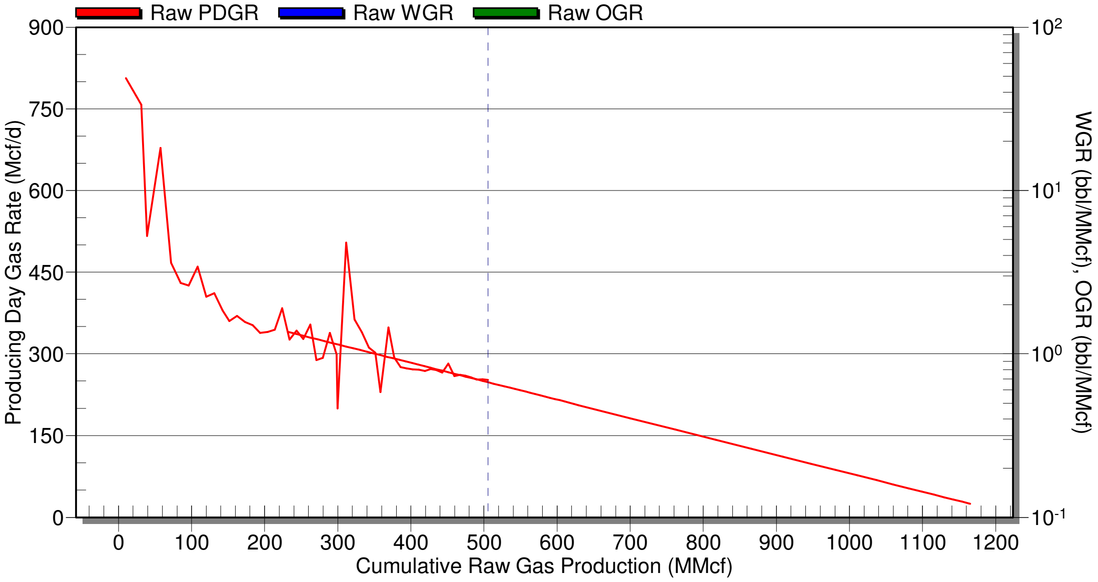
**Di units: Gas #/yr, WGR #/Mcf, Water #/yr, Oil #/yr

***Max units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

Production (6 mo. History / 6 mo. Forecast)

Date	Well Count	CDOR (bbl/d)	CDGR (Mcf/d)	CDWR (bbl/d)	FGR (bbl/MMcf)
Jan 2010	1.0	0	261	0	0.0
Feb 2010	1.0	0	259	0	0.0
Mar 2010	1.0	0	248	0	0.0
Apr 2010	1.0	0	253	0	0.0
May 2010	1.0	0	253	0	0.0
Jun 2010	1.0	0	252	0	0.0
Jul 2010	1.0	0	245	0	0.0
Aug 2010	1.0	0	243	0	0.0
Sep 2010	1.0	0	240	0	0.0
Oct 2010	1.0	0	238	0	0.0
Nov 2010	1.0	0	235	0	0.0
Dec 2010	1.0	0	233	0	0.0





(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
200/a-019-L/094-H-02/2 (Working Copy, Raw)

General	
Field	Other Areas
Pool	Kotcho
First Prod. Date	Mar 2006
Well Status	Producer:
Operator	YOHO RESOURCES INC.

12 month averages Jul 2009 through Jun 2010			
Oil Rate	CDOR	0.0	bbl/d
	PDOR	0.0	bbl/d
Raw Gas Rate	CDGR	260.4	Mcf/d
	PDGR	262.6	Mcf/d
Oil/Gas Ratio		0.0	bbl/MMcf
Water/Gas Ratio		0.0	bbl/MMcf

		Calendar Day Rates		Monthly Production			Cumulative Production					Injection		
Date	Hours	Oil	Raw Gas	Oil	Raw Gas	Water	Oil	Raw Gas	Water	OGR	FGR	Oil	Gas	Water
	hr	bbl/d	Mcf/d	Mbbl	MMcf	Mbbl	Mbbl	MMcf	Mbbl	bbl/MMcf	bbl/MMcf	Mbbl	MMcf	Mbbl
Jul 2008	574	0.0	388.7	0	12	0	0	312	0	0.0	0.0			
Aug 2008	744	0.0	363.0	0	11	0	0	323	0	0.0	0.0			
Sep 2008	720	0.0	339.3	0	10	0	0	333	0	0.0	0.0			
Oct 2008	744	0.0	311.1	0	10	0	0	343	0	0.0	0.0			
Nov 2008	672	0.0	281.5	0	8	0	0	351	0	0.0	0.0			
Dec 2008	744	0.0	229.3	0	7	0	0	358	0	0.0	0.0			
Jan 2009	744	0.0	348.4	0	11	0	0	369	0	0.0	0.0			
Feb 2009	672	0.0	292.8	0	8	0	0	377	0	0.0	0.0			
Mar 2009	744	0.0	275.4	0	9	0	0	386	0	0.0	0.0			
Apr 2009	720	0.0	272.9	0	8	0	0	394	0	0.0	0.3			
May 2009	744	0.0	271.2	0	8	0	0	402	0	0.0	0.0			
Jun 2009	720	0.0	270.6	0	8	0	0	411	0	0.0	0.0			
Jul 2009	744	0.0	268.1	0	8	0	0	419	0	0.0	0.0			
Aug 2009	696	0.0	254.4	0	8	0	0	427	0	0.0	0.0			
Sep 2009	720	0.0	270.2	0	8	0	0	435	0	0.0	0.0			
Oct 2009	744	0.0	265.5	0	8	0	0	443	0	0.0	0.0			
Nov 2009	720	0.0	282.1	0	8	0	0	452	0	0.0	0.0			
Dec 2009	744	0.0	258.8	0	8	0	0	460	0	0.0	0.0			
Jan 2010	744	0.0	261.2	0	8	0	0	468	0	0.0	0.0			
Feb 2010	672	0.0	259.5	0	7	0	0	475	0	0.0	0.0			
Mar 2010	720	0.0	248.3	0	8	0	0	483	0	0.0	0.0			
Apr 2010	720	0.0	252.7	0	8	0	0	490	0	0.0	0.0			
May 2010	744	0.0	253.0	0	8	0	0	498	0	0.0	0.0			
Jun 2010	720	0.0	251.9	0	8	0	0	506	0	0.0	0.0			
Jul 2010	740	0.0	245.1	0	8	0	0	513	0	0.0	0.0			
Aug 2010	740	0.0	242.5	0	8	0	0	521	0	0.0	0.0			
Sep 2010	716	0.0	240.1	0	7	0	0	528	0	0.0	0.0			
Oct 2010	740	0.0	237.6	0	7	0	0	535	0	0.0	0.0			
Nov 2010	716	0.0	235.2	0	7	0	0	542	0	0.0	0.0			
Dec 2010	740	0.0	232.8	0	7	0	0	550	0	0.0	0.0			
Jan 2011	740	0.0	230.4	0	7	0	0	557	0	0.0	0.0			
Feb 2011	668	0.0	228.1	0	6	0	0	563	0	0.0	0.0			
Mar 2011	740	0.0	225.9	0	7	0	0	570	0	0.0	0.0			
Apr 2011	716	0.0	223.6	0	7	0	0	577	0	0.0	0.0			
May 2011	740	0.0	221.3	0	7	0	0	584	0	0.0	0.0			
Jun 2011	716	0.0	219.0	0	7	0	0	590	0	0.0	0.0			
Jul 2011	740	0.0	216.8	0	7	0	0	597	0	0.0	0.0			
Aug 2011	740	0.0	214.6	0	7	0	0	604	0	0.0	0.0			
Sep 2011	716	0.0	212.4	0	6	0	0	610	0	0.0	0.0			
Oct 2011	740	0.0	210.2	0	7	0	0	616	0	0.0	0.0			
Nov 2011	716	0.0	208.1	0	6	0	0	623	0	0.0	0.0			
Dec 2011	740	0.0	206.0	0	6	0	0	629	0	0.0	0.0			
Dec 2012	8,737	0.0	192.8	0	71	0	0	700	0	0.0	0.0			
Dec 2013	8,713	0.0	170.5	0	62	0	0	762	0	0.0	0.0			
Dec 2014	8,713	0.0	150.9	0	55	0	0	817	0	0.0	0.0			
Dec 2015	8,713	0.0	133.5	0	49	0	0	866	0	0.0	0.0			
Dec 2016	8,737	0.0	118.0	0	43	0	0	909	0	0.0	0.0			
Dec 2017	8,713	0.0	104.4	0	38	0	0	947	0	0.0	0.0			
Dec 2018	8,713	0.0	92.4	0	34	0	0	981	0	0.0	0.0			
Dec 2019	8,713	0.0	81.7	0	30	0	0	1,011	0	0.0	0.0			
Dec 2020	8,737	0.0	72.3	0	26	0	0	1,037	0	0.0	0.0			
Dec 2021	8,713	0.0	63.9	0	23	0	0	1,060	0	0.0	0.0			
Dec 2022	8,713	0.0	56.6	0	21	0	0	1,081	0	0.0	0.0			
Dec 2023	8,713	0.0	50.0	0	18	0	0	1,099	0	0.0	0.0			
Dec 2024	8,737	0.0	44.3	0	16	0	0	1,115	0	0.0	0.0			
Dec 2025	8,713	0.0	39.1	0	14	0	0	1,130	0	0.0	0.0			
Dec 2026	8,713	0.0	34.6	0	13	0	0	1,142	0	0.0	0.0			
Dec 2027	8,713	0.0	30.6	0	11	0	0	1,154	0	0.0	0.0			
Dec 2028	8,737	0.0	27.1	0	10	0	0	1,163	0	0.0	0.0			
Mar 2029	1,688	0.0	25.2	0	2	0	0	1,165	0	0.0	0.0			

Well List

200/a-019-L/094-H-02/2

(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
200/a-019-L/094-H-02/2 (Working Copy, Raw)

General

Production Status	Producer:
Well Name	YOHO PICKELL A- 019-L/094-H- 02
Field Name	Other Areas
Pool Name	Kotcho
Lithology	
Reserves based on	Decline Analysis

Reservoir Volumetric Values

KB Elevation	-	ft
Formation Top (KB)	-	ft
Formation Bottom (KB)	-	ft
Gross Pay	-	ft
Gross Rock Volume	-	Ac·ft
Gross Pore Volume	-	Ac·ft
Gas Hydrocarbon PV	-	Ac·ft
OGIP / Gross Rock Vol.	-	Mcf/(Ac·ft)
Pool Area	-	Ac
Current Pressure	-	psia
Productive Area (A)	-	Ac
Net Pay (h)	-	ft
Porosity (Phi)	-	%
Phi*h	-	ft
Water Saturation (Sw)	-	%
Oil Saturation (So)	-	%
Gas Saturation (Sg)	-	%
Initial Pressure	-	psia
Reservoir Temperature	-	°F
Z Factor	1.0000	
Bg (Gas Form. Vol. Factor)	-	

Gross Volumetric Reserves

Original Gas In Place (OGIP)	-	MMcf
Recovery Factor	-	%
Original Recoverable Raw GIP (ORRGIP)	-	MMcf
Cum. Prod. through Aug 2010	520.7	MMcf
Rem. Recoverable Raw GIP	-	MMcf
Total Gas Loss	7.00	%
Original Recoverable Sales GIP (ORSGIP)	-	MMcf
Cum. Sales through Aug 2010	484.3	MMcf
Rem. Recoverable Sales GIP	-	MMcf
Start of Forecast	Jul 1, 2010	
Cum. Prod. up to Fcst. Start	505.6	MMcf

(default company)

Economic Reserves at September 1, 2010
Proved Developed Producing
200/a-019-L/094-H-02/2 (Working Copy)

Summary

Reserve Category	Proved Developed Producing	Primary Phase	GAS
Author		Last Modified By	admin
Client		Last Modified	Sep 1, 2010 6:08:39 AM
Price Schedule	Sample		
Database	H:\Value Navigator\Mike Jean Marie 2 wells.rdb		

Well Information

Entity	200/a-019-L/094-H-02/2	Field	Other Areas
Name	YOHO PICKELL A- 019-L/094-H- 02	Pool	Kotcho
Country	Canada	Unit	N/A
Province	British Columbia	GCI Depth	0.0 ft
On-time	99.46%		

Comments

None

Project Economic Options

Discounting Rates	5.0%, 8.0%, 10.0%, 15.0%, 20.0%		
Reference Date (As Of)	September 1, 2010		
Econ. Calculation Start Date	September 1, 2010		
Abandonment Capital	Enabled	ARTC	Disabled
Salvage Capital	Enabled	Saskatchewan Capital Surcharge	Enabled
Economic Limit	Enabled		

General Information

	Delay	Cost	Template Links	
Abandonment	- mo	- M$	Op. Costs	N/A
Salvage	- mo	- M$	Cap. Costs	N/A
			Prices	N/A
Chance of Success	100.0%			
Chance of Occurrence	100.0%	Posted Min. Price		
Economic Limit	Applied			

Decline Information

Reserve Category Proved Developed Producing

Segment	Start Date	Qi	Di (nom)	Ni	Max.	Qf	Gross Ult.	Gross Rem.
Gas 1	Jun 2010	247.69 Mcf/d	0.1233 #/yr	-	582.95 Mcf/d	25.00 Mcf/d	1,165 MMcf	645 MMcf

Product	Ratio		Theo. Yield bbl/MMcf	Gas Analysis %
Oil	-	bbl/MMcf		
Gas	-	scf/bbl		
Cond.	-	bbl/MMcf		
NGL	-	bbl/MMcf		
C5+	-	bbl/MMcf	-	-
C4	-	bbl/MMcf	-	-
C3	-	bbl/MMcf	-	-
C2	-	bbl/MMcf	-	-
S2	-	LT/MMcf		-

Energy Content		1,005.0	BTU/scf
Gas Shrinkage	Surface Loss	7.0	%
	Process Loss	-	%
	Total Loss	7.0	%
Remaining Reserves	Volumetrics	-	MMcf
	P/Z	-	MMcf
	OGR	-	bbl/MMcf

Production

Date	Well Count	Oil (bbl)	Raw Gas (Mcf)	Sales Gas (Mcf)	Water (bbl)	NGL (bbl)	Condensate (bbl)	C2 (bbl)	C3 (bbl)	C4 (bbl)	C5+ (bbl)	Sulphur (LT)
Sep 2010	1.00	-	7,202.2	6,698.0	-	-	-	-	-	-	-	-
Oct 2010	1.00	-	7,366.4	6,850.8	-	-	-	-	-	-	-	-
Nov 2010	1.00	-	7,056.2	6,562.2	-	-	-	-	-	-	-	-
Dec 2010	1.00	-	7,217.1	6,711.9	-	-	-	-	-	-	-	-
Jan 2011	1.00	-	7,142.3	6,642.4	-	-	-	-	-	-	-	-
Feb 2011	1.00	-	6,387.6	5,940.4	-	-	-	-	-	-	-	-
Mar 2011	1.00	-	7,002.2	6,512.1	-	-	-	-	-	-	-	-
Apr 2011	1.00	-	6,707.3	6,237.8	-	-	-	-	-	-	-	-
May 2011	1.00	-	6,860.3	6,380.0	-	-	-	-	-	-	-	-
Jun 2011	1.00	-	6,571.3	6,111.3	-	-	-	-	-	-	-	-
Jul 2011	1.00	-	6,721.2	6,250.7	-	-	-	-	-	-	-	-
Aug 2011	1.00	-	6,651.6	6,186.0	-	-	-	-	-	-	-	-

Production

Date	Well Count	Oil (bbl)	Raw Gas (Mcf)	Sales Gas (Mcf)	Water (bbl)	NGL (bbl)	Condensate (bbl)	C2 (bbl)	C3 (bbl)	C4 (bbl)	C5+ (bbl)	Sulphur (LT)
Sep 2011	1.00	-	6,371.4	5,925.4	-	-	-	-	-	-	-	-
Oct 2011	1.00	-	6,516.7	6,060.5	-	-	-	-	-	-	-	-
Nov 2011	1.00	-	6,242.2	5,805.3	-	-	-	-	-	-	-	-
Dec 2011	1.00	-	6,384.6	5,937.7	-	-	-	-	-	-	-	-
Dec 2012	1.00	-	70,563.0	65,623.6	-	-	-	-	-	-	-	-
Dec 2013	1.00	-	62,242.4	57,885.5	-	-	-	-	-	-	-	-
Dec 2014	1.00	-	55,062.9	51,208.5	-	-	-	-	-	-	-	-
Dec 2015	1.00	-	48,711.4	45,301.6	-	-	-	-	-	-	-	-
Dec 2016	1.00	-	43,203.6	40,179.4	-	-	-	-	-	-	-	-
Dec 2017	1.00	-	38,109.2	35,441.5	-	-	-	-	-	-	-	-
Dec 2018	1.00	-	33,713.3	31,353.4	-	-	-	-	-	-	-	-
Dec 2019	1.00	-	29,824.6	27,736.8	-	-	-	-	-	-	-	-
Dec 2020	1.00	-	26,452.3	24,600.6	-	-	-	-	-	-	-	-
Dec 2021	1.00	-	23,333.1	21,699.8	-	-	-	-	-	-	-	-
Dec 2022	1.00	-	20,641.7	19,196.8	-	-	-	-	-	-	-	-
Dec 2023	1.00	-	18,260.7	16,982.4	-	-	-	-	-	-	-	-
Dec 2024	1.00	-	16,195.9	15,062.2	-	-	-	-	-	-	-	-
Dec 2025	1.00	-	14,286.2	13,286.1	-	-	-	-	-	-	-	-
Dec 2026	1.00	-	12,638.3	11,753.6	-	-	-	-	-	-	-	-
Dec 2027	1.00	-	11,180.5	10,397.8	-	-	-	-	-	-	-	-
Dec 2028	1.00	-	9,916.3	9,222.1	-	-	-	-	-	-	-	-
Dec 2029	1.00	-	1,778.9	1,654.3	-	-	-	-	-	-	-	-
Total		**-**	**644,514.8**	**599,398.8**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Capital Costs

No Data.

Operating Costs

No Data.

Prices

Price Deck: Sample Base

	OIL	GAS	CON	NGL	C2	C3	C4	C5+	S2
Product	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Parent	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base
Unit	$/bbl	$/MMBTU	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/LT
Jan 2005	56.46	8.62	57.09	38.81	19.63	31.83	37.33	57.09	34.08
Jan 2006	66.09	7.23	66.16	49.04	17.49	38.88	52.31	66.16	17.02
Jan 2007	72.27	6.86	72.31	56.16	17.22	46.32	59.58	72.31	35.55
Jan 2008	99.59	9.04	98.76	69.50	21.31	55.46	70.83	98.76	286.60
Jan 2009	57.28	4.37	56.91	40.45	10.55	35.65	37.22	56.91	11.40
Jan 2010	60.00	5.00	58.00	42.00	11.00	36.00	38.00	58.00	12.00

Allowances

Transportation

Area		
C3	-	$/Mcf
C4	-	$/Mcf
C5+	-	$/Mcf
NGL	-	$/Mcf

Royalty Allowance

Fractionation	-	$/bbl
Storage	-	$/bbl

Gas Cost Allowance (based on sales volumes)

Return on Rate Base	15.00	%
Capital Carry Forward	-	M$
Remaining Life	240.00	mo
Allocated GCA	-	$/Mcf

Ownership

- ⊟ (default) (Included)
  - ⊟ Lease 1
    - ⊟ GEN Interest

Country	Canada	Start Date	Jan 1, 1900	Incentive	<none>
Province	British Columbia	Mineral Owner	Crown		
Regime	<none>	Prod. Category	Base 9 Gas		

	BPO
Ownership	
Working Interest (%)	100
Factors	
Pooling Factor	1
Tract Factor	1

Custom Regime Fields

No Data

Change Records

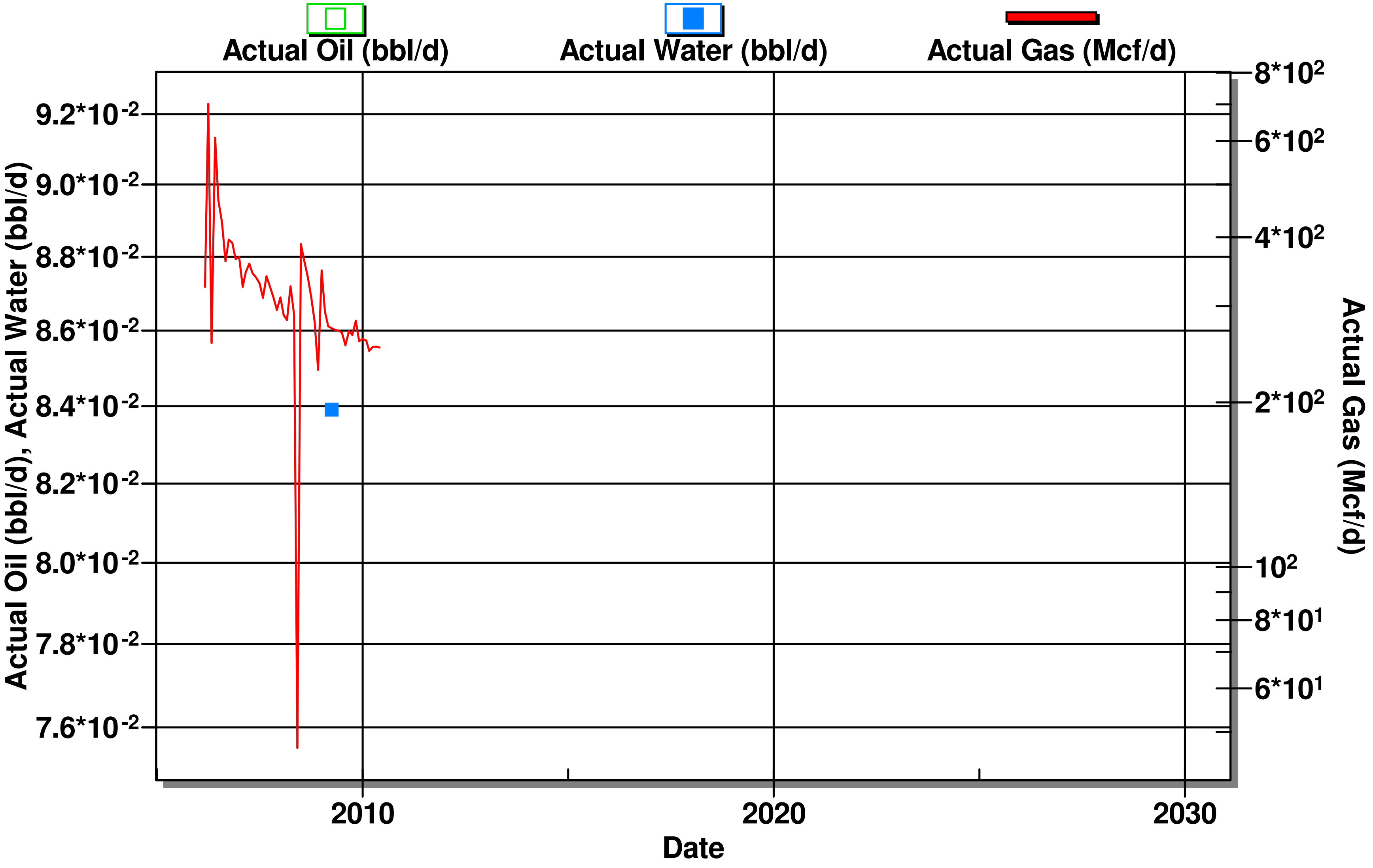
Type	Date	Status	Res. Cat	Author	Changed	Comment
200/a-019-L/094-H-02/2						
No Changes						

Well List

200/a-019-L/094-H-02/2

Semi-Log Rate-Time

UWID = '200/a-019-L/094-H-02/2' And Status = 'Working' And Res. Cat. = 'PDP', Raw
UWID = 200/a-019-L/094-H-02/2

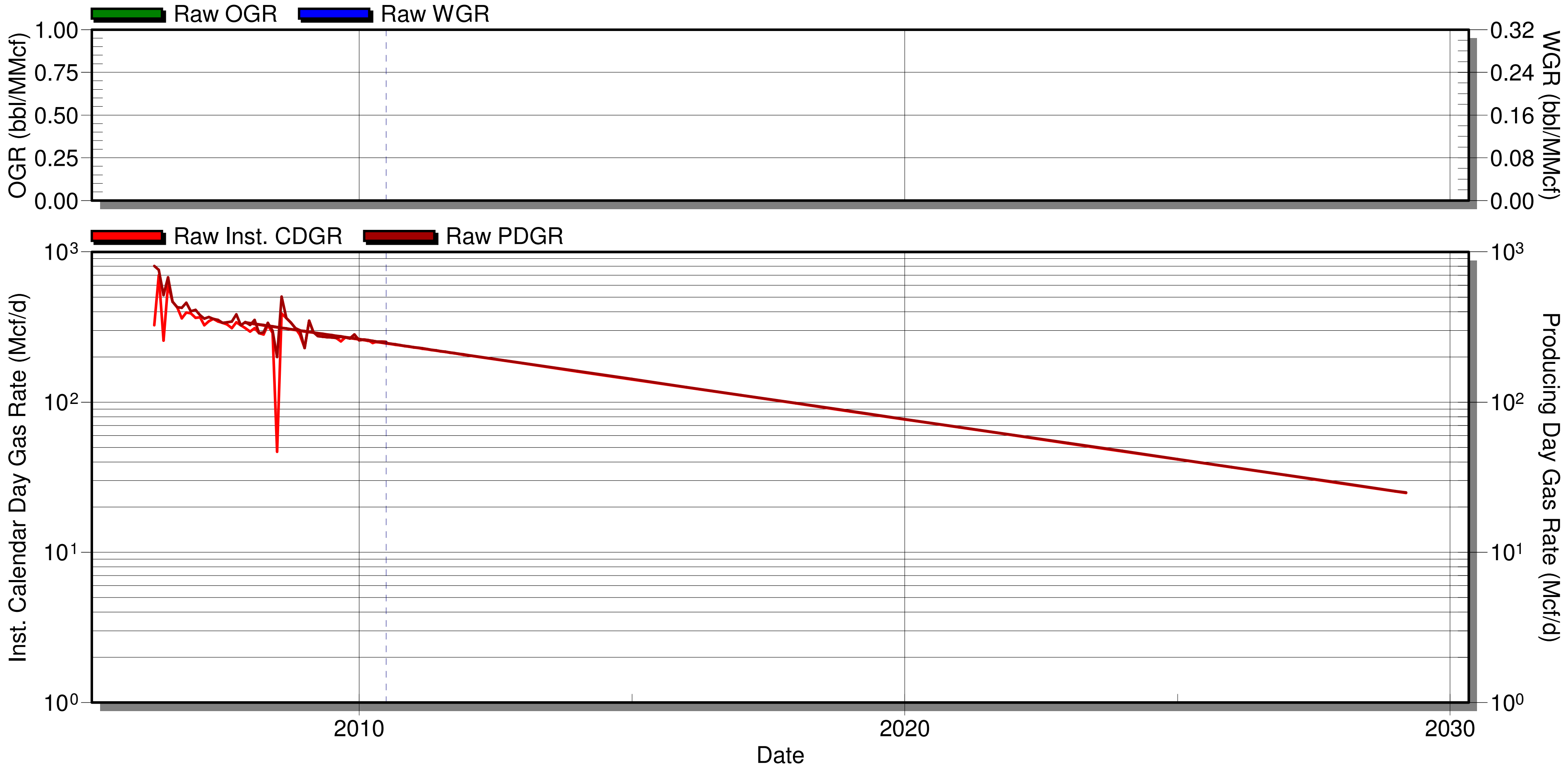


(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
200/a-019-L/094-H-02/2 (Working Copy, Raw)

Summary

Status	Producer:	**On-time**	99.46%
Field	Other Areas	**WI**	100.00%
Pool	Kotcho	**RLI**	7.4
Operator	YOHO RESOURCES INC.	**Rem. Prod. Life**	19.3 yr



Technical Reserves at Sep 1, 2010 (Based on Dec. Analysis)

	Gross Ult.	Cumulative Production Hist. To Fcst. Start	Fcst. To Ref. Date	Total	Gross Rem.	WI Rem.
Oil (Mbbl)	0.0	0.0	0.0	0.0	0.0	0.0
Gas (MMcf)	1,165.2	505.6	15.1	520.7	644.5	644.5
Water (Mbbl)	0.0	0.0	0.0	0.0	0.0	0.0

Declines

Segment	Date	Qi	Di (Nom)	Ni	Max	Qf
Gas 1	Jun 2010	247.7 Mcf/d	0.123306 #/yr	0.00	582.9 Mcf/d	25.0 Mcf/d

ESTIMATE OF GAS RESERVES

Area: Pickell
Well: C-8-L-94-H-2
Pool Zone: Jean Marie

RESERVOIR PARAMETERS

Top of Gross Pay	2456.0	m	8057.7	ft
Base of Gross Pay	2467.5	m	8095.4	ft
Gas/Oil or Gas/Water contact	N/A	m		ft
Porosity		3.0%		3.0%
Initial Water Saturation		20%		20%
Residual Oil Saturation		0%		0%
Initial Reservoir Pressure		34612kpa		5,020psi
Reservoir Temperature		99 °C		210 °F
Compressibility Factor		1.034		1.034
Productive Area		32ha		80acres
Average Net Pay		10m		32.8ft
Recovery Factor		65%		65%
Surface Loss		7%		7%
Initial Raw GIP	20.3	10^6m^3	721	Mmcf
Initial Recoverable Raw GIP	13.2	10^6m^3	469	Mmcf
Initial Marketable GIP	12.7	10^6m^3	451	Mmcf
Cum Raw Production	0.5	10^6m^3	18.0	Mmcf
Cum Sales Prod. To Aug 31	0.47	10^6m^3	16.7	Mmcf
Remaining Marketable GIP	11.8	10^6m^3	419.3	Mmcf

Gas Gravity	0.562		0.562	
N2 Concentration	0.95	%	0.95	%
CO2 Concentration	1.07	%	1.07	%
H2S Concentration	0.00	%	0.00	0%
Critical Pressure	4618	kpa	669.8	psi
Critical Temperature	211	°K	379.8	°R
Gross Heating Value	37.65	MJ/m^3	1006	BTU/scf

(default company)

Technical Reserves at September 1, 2010

c-8-L/094-H-2/0 (Working Copy, Raw)

Field / Pool /
Lithology

Reservoir Volumetric Values		**PDP**	**PNP**	**PUD**	**P+PDP**	**P+PNP**	**P+PUD**
KB Elevation	ft						
Formation Top (KB)	ft						
Formation Bottom (KB)	ft						
Gross Pay	ft						
Gross Rock Volume	Ac·ft	2,640.0					
Gross Pore Volume	Ac·ft	79.2					
Gas Hydrocarbon PV	Ac·ft	63.4					
OGIP / Gross Rock Vol.	Mcf/(Ac·ft)	273.2					
Pool Area	Ac						
Current Pressure	psia						
Productive Area (A)	Ac	80					
Net Pay (h)	ft	33.0					
Porosity (Phi)	%	3.0					
Phi*h	ft	0.99					
Water Saturation (Sw)	%	20.0					
Oil Saturation (So)	%	-					
Gas Saturation (Sg)	%	80.0					
Initial Pressure	psia	5,020.0					
Reservoir Temperature	°F	212.0					
Z Factor		1.0110					
Bg (Gas Form. Vol. Factor)		0.0038					

Material Balance Factors		
Pi	psia	
PAbandon	psia	

Gross Technical Reserves		
Orig. Gas In Place	MMcf	721.3
Recovery Factor	%	65.00
Orig. Rec. Raw Gas In Place	MMcf	468.8
Cum. Prod. through Aug 2010	MMcf	18.0
Rem. Rec. Raw Gas In Place	MMcf	450.8
Total Gas Loss	%	7.00
Orig. Rec. Sales Gas In Place	MMcf	436.0
Cum. Sales through Aug 2010	MMcf	16.7
Rem. Rec. Sales Gas In Place	MMcf	419.3
Start of Forecast		Jul 1, 2010
Cum. Prod. up to Fcst. Start	MMcf	-
Based On		**Volumetrics**

Declines

Segment	Res Cat	Date	Qi	Di (Nom)	Ni	Max	Qf
Gas 1	PDP	Jun 2010	300.0 Mcf/d	0.409388 #/yr	0.7000	200,000.0 Mcf/d	25.0 Mcf/d

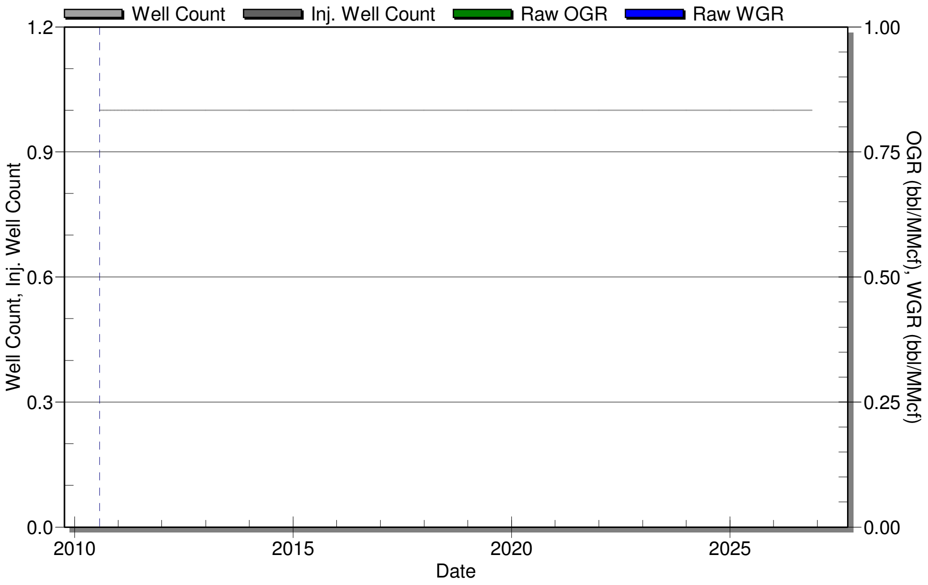
(default company)

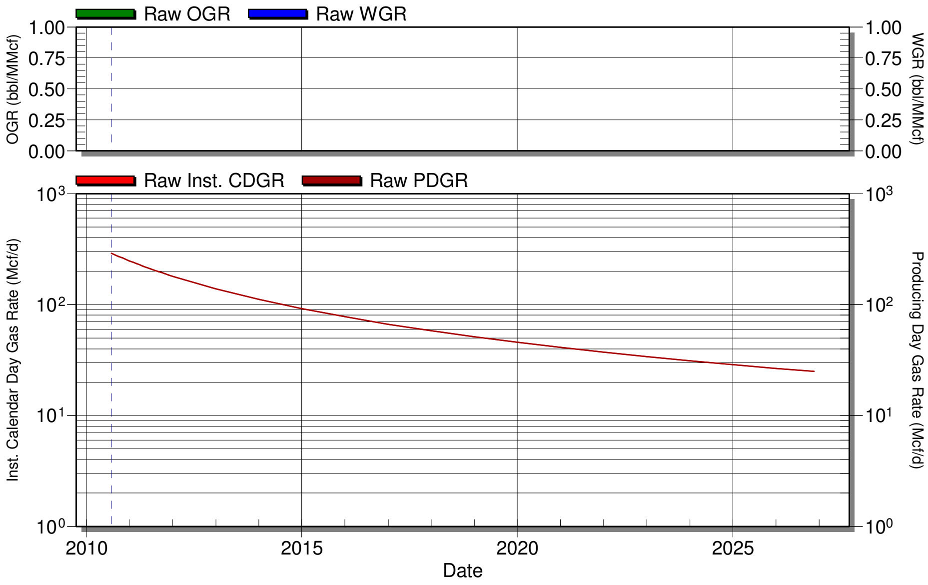
Technical Reserves at September 1, 2010
Proved Developed Producing
c-8-L/094-H-2/0 (Working Copy, Raw)

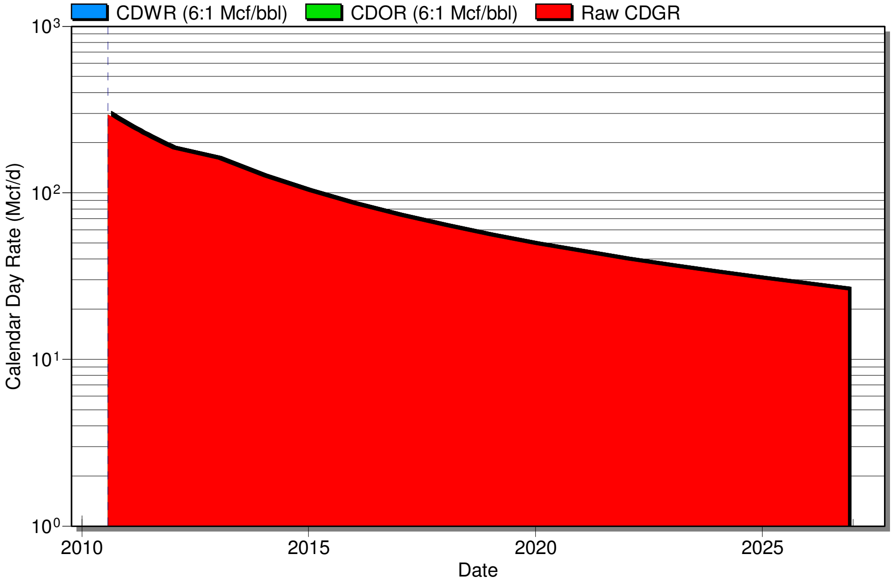
Date	Wells	CDOR (bbl/d)	Cum Oil (Mbbl)	CDGR (Mcf/d)	Cum Gas (MMcf)	CDBOE (bbl/d)	Cum BOE (Mbbl)	CDWR (bbl/d)	Cum Water (Mbbl)	OGR (bbl/MMcf)	FGR (bbl/MMcf)	Hours (hr)
Jul 2010	1.00	0.0	0	294.9	9	49.1	2	0.0	0	0.0	0.0	744
Aug 2010	1.00	0.0	0	285.1	18	47.5	3	0.0	0	0.0	0.0	744
Sep 2010	1.00	0.0	0	275.9	26	46.0	4	0.0	0	0.0	0.0	720
Oct 2010	1.00	0.0	0	267.2	35	44.5	6	0.0	0	0.0	0.0	744
Nov 2010	1.00	0.0	0	259.0	42	43.2	7	0.0	0	0.0	0.0	720
Dec 2010	1.00	0.0	0	251.3	50	41.9	8	0.0	0	0.0	0.0	744
Jan 2011	1.00	0.0	0	243.7	58	40.6	10	0.0	0	0.0	0.0	744
Feb 2011	1.00	0.0	0	236.9	64	39.5	11	0.0	0	0.0	0.0	672
Mar 2011	1.00	0.0	0	230.4	71	38.4	12	0.0	0	0.0	0.0	744
Apr 2011	1.00	0.0	0	224.1	78	37.3	13	0.0	0	0.0	0.0	720
May 2011	1.00	0.0	0	218.0	85	36.3	14	0.0	0	0.0	0.0	744
Jun 2011	1.00	0.0	0	212.1	91	35.4	15	0.0	0	0.0	0.0	720
Jul 2011	1.00	0.0	0	206.6	98	34.4	16	0.0	0	0.0	0.0	744
Aug 2011	1.00	0.0	0	201.2	104	33.5	17	0.0	0	0.0	0.0	744
Sep 2011	1.00	0.0	0	196.1	110	32.7	18	0.0	0	0.0	0.0	720
Oct 2011	1.00	0.0	0	191.2	116	31.9	19	0.0	0	0.0	0.0	744
Nov 2011	1.00	0.0	0	186.5	121	31.1	20	0.0	0	0.0	0.0	720
Dec 2011	1.00	0.0	0	182.1	127	30.3	21	0.0	0	0.0	0.0	744
Dec 2012	1.00	0.0	0	157.6	185	26.3	31	0.0	0	0.0	0.0	8,784
Dec 2013	1.00	0.0	0	123.9	230	20.7	38	0.0	0	0.0	0.0	8,760
Dec 2014	1.00	0.0	0	100.9	267	16.8	44	0.0	0	0.0	0.0	8,760
Dec 2015	1.00	0.0	0	84.4	298	14.1	50	0.0	0	0.0	0.0	8,760
Dec 2016	1.00	0.0	0	71.9	324	12.0	54	0.0	0	0.0	0.0	8,784
Dec 2017	1.00	0.0	0	62.3	347	10.4	58	0.0	0	0.0	0.0	8,760
Dec 2018	1.00	0.0	0	54.7	367	9.1	61	0.0	0	0.0	0.0	8,760
Dec 2019	1.00	0.0	0	48.6	384	8.1	64	0.0	0	0.0	0.0	8,760
Dec 2020	1.00	0.0	0	43.5	400	7.2	67	0.0	0	0.0	0.0	8,784
Dec 2021	1.00	0.0	0	39.3	415	6.5	69	0.0	0	0.0	0.0	8,760
Dec 2022	1.00	0.0	0	35.7	428	5.9	71	0.0	0	0.0	0.0	8,760
Dec 2023	1.00	0.0	0	32.6	439	5.4	73	0.0	0	0.0	0.0	8,760
Dec 2024	1.00	0.0	0	30.0	450	5.0	75	0.0	0	0.0	0.0	8,784
Dec 2025	1.00	0.0	0	27.7	461	4.6	77	0.0	0	0.0	0.0	8,760
Dec 2026	1.00	0.0	0	25.8	469	4.3	78	0.0	0	0.0	0.0	7,675

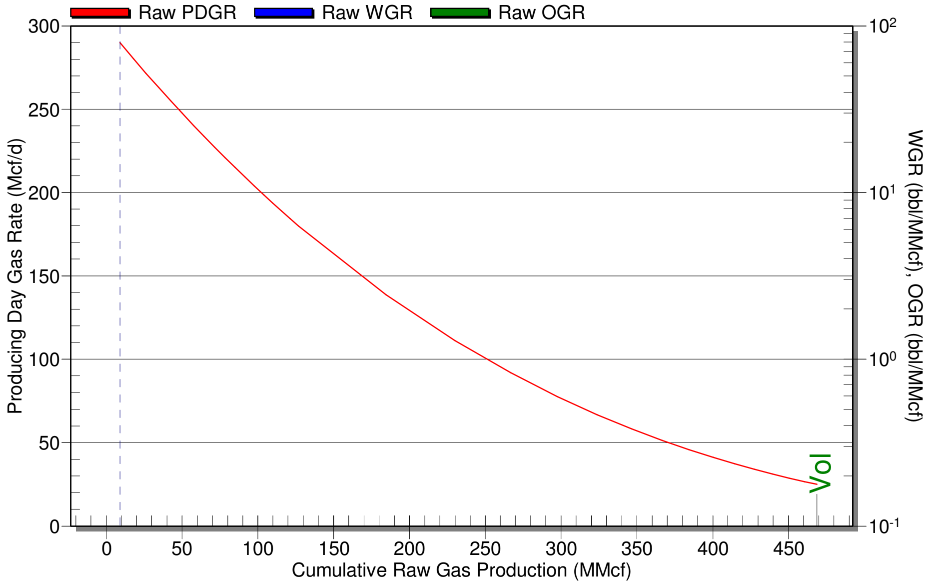
(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
c-8-L/094-H-2/0 (Working Copy, Raw)









(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
c-8-L/094-H-2/0 (Working Copy, Raw)

Status		**Aprox. On-time**	100.00%
Field		**Rig Release**	
Pool		**WI**	100.00%
Unit		**RLI**	4.5
Operator		**Type**	PDP
Licensee			Raw

Technical Reserves at Sep 1, 2010 (Based on Volumetrics)

	Ultimate Reserves	Cumulative Production	Remaining Gross	Remaining WI
Oil (Mbbl)	0.0	0.0	0.0	0.0
Gas (MMcf)	468.8	18.0	450.8	450.8
Water (Mbbl)	0.0	0.0	0.0	0.0

Declines

Segment	Start Date	Qi*	Di** (Nom)	Ni	Max***	Qf*
Gas 1	Jun 2010	300.0	0.409388	0.70	200,000.0	25.0

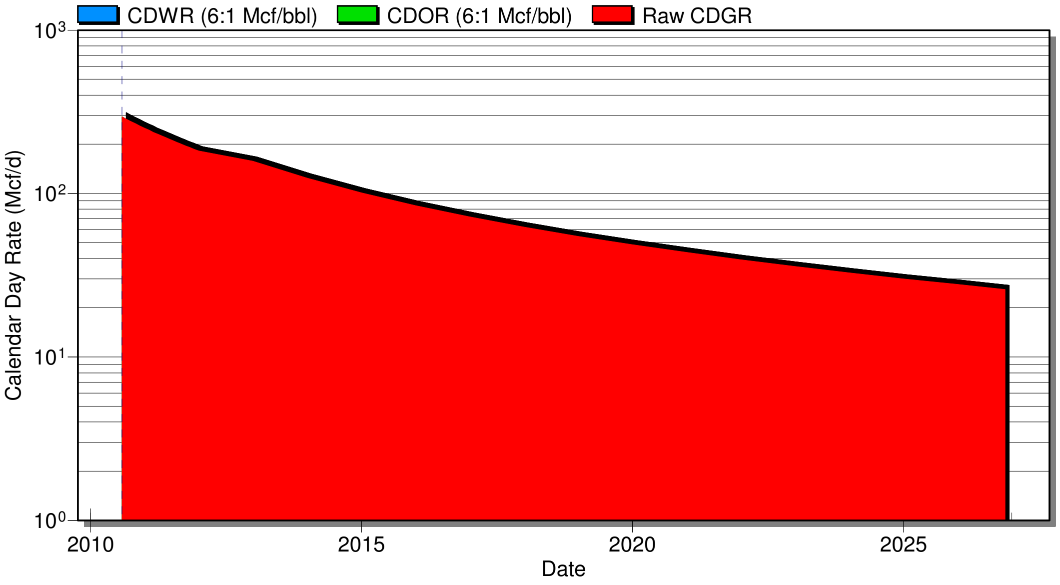
*Qi, Qf units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

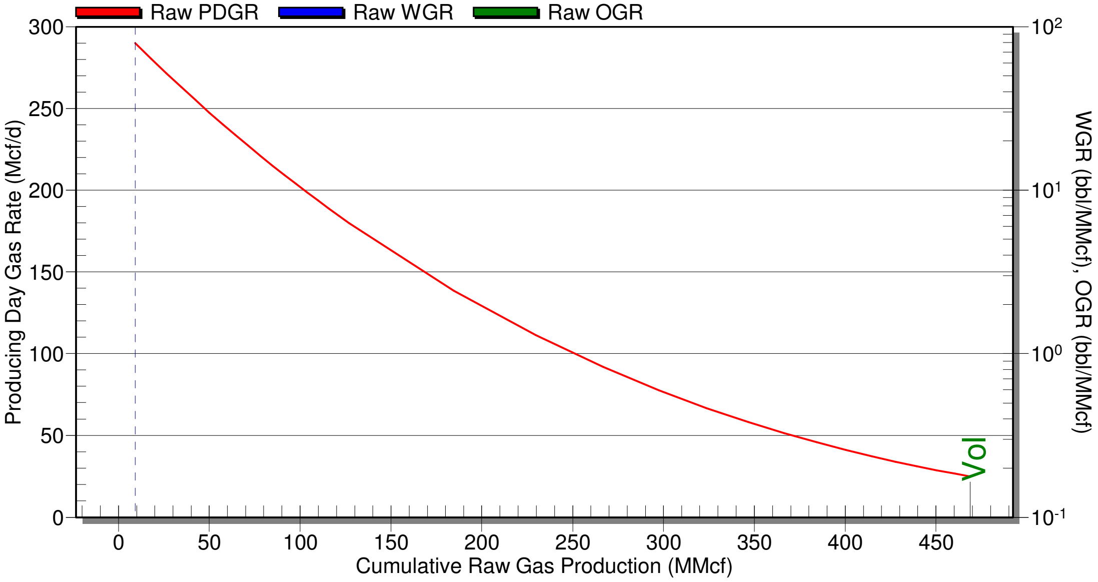
**Di units: Gas #/yr, WGR #/Mcf, Water #/yr, Oil #/yr

***Max units: Gas Mcf/d, WGR bbl/MMcf, Water bbl/d, Oil bbl/d

Production (0 mo. History / 0 mo. Forecast)

Date	Well Count	CDOR (bbl/d)	CDGR (Mcf/d)	CDWR (bbl/d)	FGR (bbl/MMcf)
Jul 2010	1.0	0	295	0	0.0
Aug 2010	1.0	0	285	0	0.0
Sep 2010	1.0	0	276	0	0.0
Oct 2010	1.0	0	267	0	0.0
Nov 2010	1.0	0	259	0	0.0
Dec 2010	1.0	0	251	0	0.0





(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
c-8-L/094-H-2/0 (Working Copy, Raw)

General

Field
Pool
First Prod. Date
Well Status
Operator

		Calendar Day Rates		Monthly Production			Cumulative Production					Injection		
Date	Hours	Oil	Raw Gas	Oil	Raw Gas	Water	Oil	Raw Gas	Water	OGR	FGR	Oil	Gas	Water
	hr	bbl/d	Mcf/d	Mbbl	MMcf	Mbbl	Mbbl	MMcf	Mbbl	bbl/MMcf	bbl/MMcf	Mbbl	MMcf	Mbbl
Jul 2010	744	0.0	294.9	0	9	0	0	9	0	0.0	0.0			
Aug 2010	744	0.0	285.1	0	9	0	0	18	0	0.0	0.0			
Sep 2010	720	0.0	275.9	0	8	0	0	26	0	0.0	0.0			
Oct 2010	744	0.0	267.2	0	8	0	0	35	0	0.0	0.0			
Nov 2010	720	0.0	259.0	0	8	0	0	42	0	0.0	0.0			
Dec 2010	744	0.0	251.3	0	8	0	0	50	0	0.0	0.0			
Jan 2011	744	0.0	243.7	0	8	0	0	58	0	0.0	0.0			
Feb 2011	672	0.0	236.9	0	7	0	0	64	0	0.0	0.0			
Mar 2011	744	0.0	230.4	0	7	0	0	71	0	0.0	0.0			
Apr 2011	720	0.0	224.1	0	7	0	0	78	0	0.0	0.0			
May 2011	744	0.0	218.0	0	7	0	0	85	0	0.0	0.0			
Jun 2011	720	0.0	212.1	0	6	0	0	91	0	0.0	0.0			
Jul 2011	744	0.0	206.6	0	6	0	0	98	0	0.0	0.0			
Aug 2011	744	0.0	201.2	0	6	0	0	104	0	0.0	0.0			
Sep 2011	720	0.0	196.1	0	6	0	0	110	0	0.0	0.0			
Oct 2011	744	0.0	191.2	0	6	0	0	116	0	0.0	0.0			
Nov 2011	720	0.0	186.5	0	6	0	0	121	0	0.0	0.0			
Dec 2011	744	0.0	182.1	0	6	0	0	127	0	0.0	0.0			
Dec 2012	8,784	0.0	157.6	0	58	0	0	185	0	0.0	0.0			
Dec 2013	8,760	0.0	123.9	0	45	0	0	230	0	0.0	0.0			
Dec 2014	8,760	0.0	100.9	0	37	0	0	267	0	0.0	0.0			
Dec 2015	8,760	0.0	84.4	0	31	0	0	298	0	0.0	0.0			
Dec 2016	8,784	0.0	71.9	0	26	0	0	324	0	0.0	0.0			
Dec 2017	8,760	0.0	62.3	0	23	0	0	347	0	0.0	0.0			
Dec 2018	8,760	0.0	54.7	0	20	0	0	367	0	0.0	0.0			
Dec 2019	8,760	0.0	48.6	0	18	0	0	384	0	0.0	0.0			
Dec 2020	8,784	0.0	43.5	0	16	0	0	400	0	0.0	0.0			
Dec 2021	8,760	0.0	39.3	0	14	0	0	415	0	0.0	0.0			
Dec 2022	8,760	0.0	35.7	0	13	0	0	428	0	0.0	0.0			
Dec 2023	8,760	0.0	32.6	0	12	0	0	439	0	0.0	0.0			
Dec 2024	8,784	0.0	30.0	0	11	0	0	450	0	0.0	0.0			
Dec 2025	8,760	0.0	27.7	0	10	0	0	461	0	0.0	0.0			
Nov 2026	7,675	0.0	25.8	0	8	0	0	469	0	0.0	0.0			

Well List

c-8-L/094-H-2/0

(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
c-8-L/094-H-2/0 (Working Copy, Raw)

General		
Production Status		
Well Name		
Field Name		
Pool Name		
Lithology		
Reserves based on	Volumetrics	

Reservoir Volumetric Values		
KB Elevation	-	ft
Formation Top (KB)	-	ft
Formation Bottom (KB)	-	ft
Gross Pay	-	ft
Gross Rock Volume	2,640.0	Ac·ft
Gross Pore Volume	79.2	Ac·ft
Gas Hydrocarbon PV	63.4	Ac·ft
OGIP / Gross Rock Vol.	273.2	Mcf/(Ac·ft)
Pool Area	-	Ac
Current Pressure	-	psia
Productive Area (A)	80	Ac
Net Pay (h)	33.0	ft
Porosity (Phi)	3.0	%
Phi*h	0.99	ft
Water Saturation (Sw)	20.0	%
Oil Saturation (So)	-	%
Gas Saturation (Sg)	80.0	%
Initial Pressure	5,020.0	psia
Reservoir Temperature	212.0	°F
Z Factor	1.0110	
Bg (Gas Form. Vol. Factor)	0.0038	

Gross Volumetric Reserves		
Original Gas In Place (OGIP)	721.3	MMcf
Recovery Factor	65.00	%
Original Recoverable Raw GIP (ORRGIP)	468.8	MMcf
Cum. Prod. through Aug 2010	18.0	MMcf
Rem. Recoverable Raw GIP	450.8	MMcf
Total Gas Loss	7.00	%
Original Recoverable Sales GIP (ORSGIP)	436.0	MMcf
Cum. Sales through Aug 2010	16.7	MMcf
Rem. Recoverable Sales GIP	419.3	MMcf
Start of Forecast		
Cum. Prod. up to Fcst. Start	-	MMcf

(default company)

Economic Reserves at September 1, 2010
Proved Developed Producing
c-8-L/094-H-2/0 (Working Copy)

Summary

Reserve Category	Proved Developed Producing	Primary Phase	GAS
Author		Last Modified By	admin
Client		Last Modified	Sep 1, 2010 6:08:54 AM
Price Schedule	Sample		
Database	H:\Value Navigator\Mike Jean Marie 2 wells.rdb		

Well Information

Entity	c-8-L/094-H-2/0	Field	
Name		Pool	
Country	Canada	Unit	
Province	British Columbia	GCI Depth	0.0 ft
On-time	100.00%		

Comments

None

Project Economic Options

Discounting Rates	5.0%, 8.0%, 10.0%, 15.0%, 20.0%		
Reference Date (As Of)	September 1, 2010		
Econ. Calculation Start Date	September 1, 2010		
Abandonment Capital	Enabled	ARTC	Disabled
Salvage Capital	Enabled	Saskatchewan Capital Surcharge	Enabled
Economic Limit	Enabled		

General Information

	Delay	Cost	Template Links	
Abandonment	- mo	- M$	Op. Costs	N/A
Salvage	- mo	- M$	Cap. Costs	N/A
			Prices	N/A
Chance of Success	100.0%			
Chance of Occurrence	100.0%	Posted Min. Price		
Economic Limit	Applied			

Decline Information

Reserve Category Proved Developed Producing

Segment	Start Date	Qi	Di (nom)	Ni	Max.	Qf	Gross Ult.	Gross Rem.
Gas 1	Jun 2010	300.00 Mcf/d	0.4094 #/yr	0.7000	200,000.00 Mcf/d	25.00 Mcf/d	469 MMcf	451 MMcf

Product	Ratio		Theo. Yield bbl/MMcf	Gas Analysis %
Oil	-	bbl/MMcf		
Gas	-	scf/bbl		
Cond.	-	bbl/MMcf		
NGL	-	bbl/MMcf		
C5+	-	bbl/MMcf	-	-
C4	-	bbl/MMcf	-	-
C3	-	bbl/MMcf	-	-
C2	-	bbl/MMcf	-	-
S2	-	LT/MMcf		-

Energy Content		1,005.0	BTU/scf
Gas Shrinkage	Surface Loss	7.0	%
	Process Loss	-	%
	Total Loss	7.0	%
Remaining Reserves	Volumetrics	468.8	MMcf
	P/Z	-	MMcf
	OGR	-	bbl/MMcf

Production

Date	Well Count	Oil (bbl)	Raw Gas (Mcf)	Sales Gas (Mcf)	Water (bbl)	NGL (bbl)	Condensate (bbl)	C2 (bbl)	C3 (bbl)	C4 (bbl)	C5+ (bbl)	Sulphur (LT)
Sep 2010	1.00	-	8,277.1	7,697.7	-	-	-	-	-	-	-	-
Oct 2010	1.00	-	8,284.7	7,704.7	-	-	-	-	-	-	-	-
Nov 2010	1.00	-	7,771.2	7,227.2	-	-	-	-	-	-	-	-
Dec 2010	1.00	-	7,788.9	7,243.7	-	-	-	-	-	-	-	-
Jan 2011	1.00	-	7,555.9	7,027.0	-	-	-	-	-	-	-	-
Feb 2011	1.00	-	6,634.1	6,169.7	-	-	-	-	-	-	-	-
Mar 2011	1.00	-	7,143.9	6,643.8	-	-	-	-	-	-	-	-
Apr 2011	1.00	-	6,721.6	6,251.1	-	-	-	-	-	-	-	-
May 2011	1.00	-	6,756.6	6,283.6	-	-	-	-	-	-	-	-
Jun 2011	1.00	-	6,363.9	5,918.4	-	-	-	-	-	-	-	-
Jul 2011	1.00	-	6,403.6	5,955.4	-	-	-	-	-	-	-	-
Aug 2011	1.00	-	6,236.1	5,799.5	-	-	-	-	-	-	-	-

Production

Date	Well Count	Oil (bbl)	Raw Gas (Mcf)	Sales Gas (Mcf)	Water (bbl)	NGL (bbl)	Condensate (bbl)	C2 (bbl)	C3 (bbl)	C4 (bbl)	C5+ (bbl)	Sulphur (LT)
Sep 2011	1.00	-	5,882.3	5,470.5	-	-	-	-	-	-	-	-
Oct 2011	1.00	-	5,927.3	5,512.4	-	-	-	-	-	-	-	-
Nov 2011	1.00	-	5,596.0	5,204.3	-	-	-	-	-	-	-	-
Dec 2011	1.00	-	5,643.7	5,248.6	-	-	-	-	-	-	-	-
Dec 2012	1.00	-	57,694.4	53,655.7	-	-	-	-	-	-	-	-
Dec 2013	1.00	-	45,239.5	42,072.7	-	-	-	-	-	-	-	-
Dec 2014	1.00	-	36,842.3	34,263.3	-	-	-	-	-	-	-	-
Dec 2015	1.00	-	30,791.6	28,636.2	-	-	-	-	-	-	-	-
Dec 2016	1.00	-	26,323.5	24,480.9	-	-	-	-	-	-	-	-
Dec 2017	1.00	-	22,743.2	21,151.1	-	-	-	-	-	-	-	-
Dec 2018	1.00	-	19,967.4	18,569.7	-	-	-	-	-	-	-	-
Dec 2019	1.00	-	17,722.5	16,481.9	-	-	-	-	-	-	-	-
Dec 2020	1.00	-	15,916.6	14,802.5	-	-	-	-	-	-	-	-
Dec 2021	1.00	-	14,329.5	13,326.4	-	-	-	-	-	-	-	-
Dec 2022	1.00	-	13,026.5	12,114.6	-	-	-	-	-	-	-	-
Dec 2023	1.00	-	11,912.9	11,079.0	-	-	-	-	-	-	-	-
Dec 2024	1.00	-	10,980.9	10,212.2	-	-	-	-	-	-	-	-
Dec 2025	1.00	-	10,113.8	9,405.8	-	-	-	-	-	-	-	-
Dec 2026	1.00	-	8,255.4	7,677.5	-	-	-	-	-	-	-	-
Total		**-**	**450,846.7**	**419,287.4**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Capital Costs

No Data.

Operating Costs

No Data.

Prices

Price Deck: Sample Base

	OIL	GAS	CON	NGL	C2	C3	C4	C5+	S2
Product	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Parent	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base	Sample Base
Unit	$/bbl	$/MMBTU	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/LT
Jan 2005	56.46	8.62	57.09	38.81	19.63	31.83	37.33	57.09	34.08
Jan 2006	66.09	7.23	66.16	49.04	17.49	38.88	52.31	66.16	17.02
Jan 2007	72.27	6.86	72.31	56.16	17.22	46.32	59.58	72.31	35.55
Jan 2008	99.59	9.04	98.76	69.50	21.31	55.46	70.83	98.76	286.60
Jan 2009	57.28	4.37	56.91	40.45	10.55	35.65	37.22	56.91	11.40
Jan 2010	60.00	5.00	58.00	42.00	11.00	36.00	38.00	58.00	12.00

Allowances

Transportation			**Royalty Allowance**		
Area					
C3	-	$/Mcf	Fractionation	-	$/bbl
C4	-	$/Mcf	Storage	-	$/bbl
C5+	-	$/Mcf			
NGL	-	$/Mcf			

Gas Cost Allowance (based on sales volumes)

Return on Rate Base	15.00	%
Capital Carry Forward	-	M$
Remaining Life	240.00	mo
Allocated GCA	-	$/Mcf

Ownership

- ⊟ (default) (Included)
  - ⊟ Lease 1
    - ⊟ GEN Interest

Country	Canada	Start Date	Jan 1, 1900	Incentive	<none>
Province	British Columbia	Mineral Owner	Crown		
Regime	<none>	Prod. Category	Base 9 Gas		

	BPO
Ownership	
Working Interest (%)	100
Factors	
Pooling Factor	1
Tract Factor	1

Custom Regime Fields

No Data

Change Records

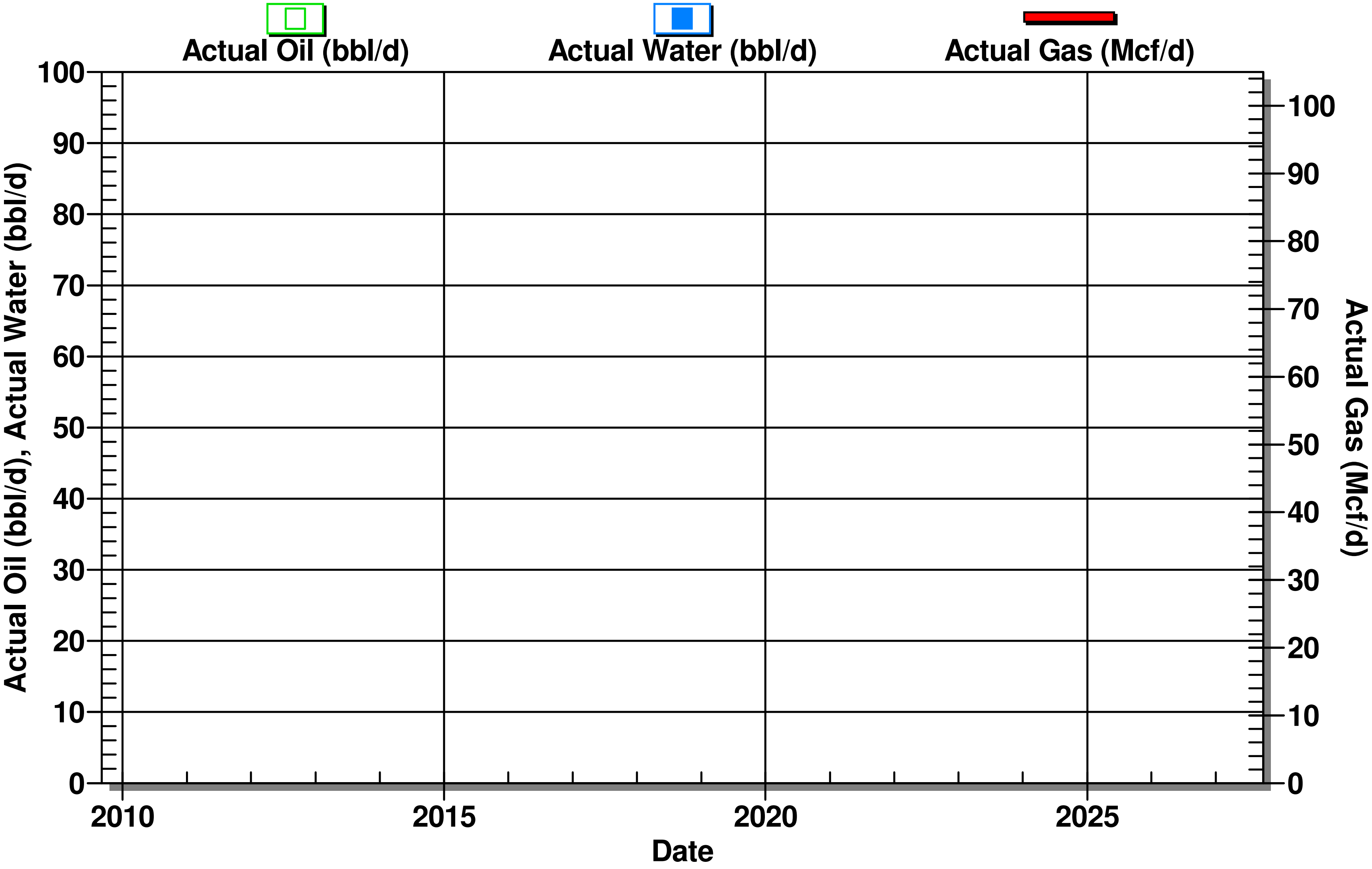
Type	Date	Status	Res. Cat	Author	Changed	Comment
c-8-L/094-H-2/0						
No Changes						

Well List

c-8-L/094-H-2/0

Semi-Log Rate-Time

UWID = 'c-8-L/094-H-2/0' And Status = 'Working' And Res. Cat. = 'PDP', Raw
UWID = c-8-L/094-H-2/0

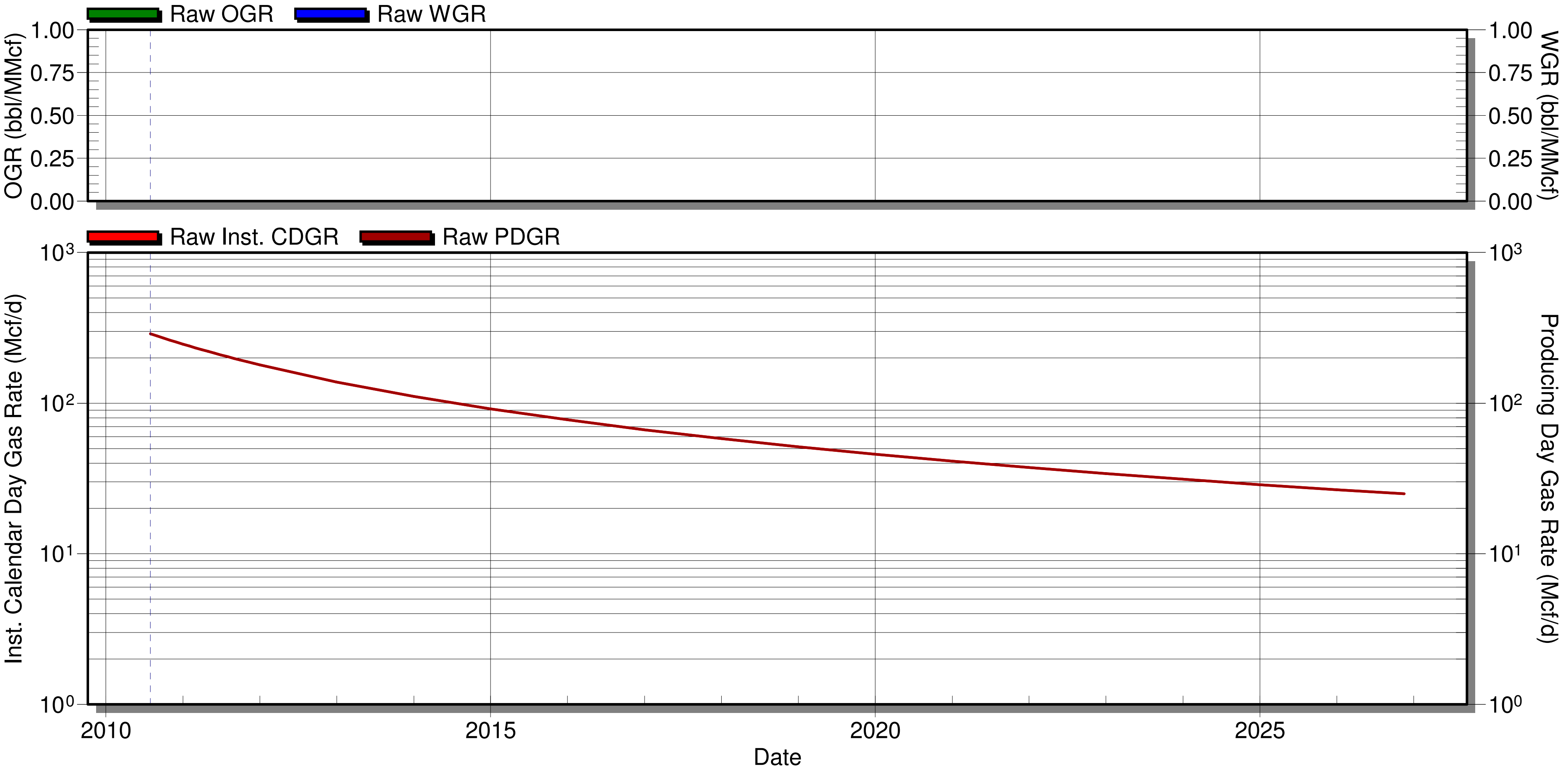


(default company)

Technical Reserves at September 1, 2010
Proved Developed Producing
c-8-L/094-H-2/0 (Working Copy, Raw)

Summary

Status		**On-time**	100.00%
Field		**WI**	100.00%
Pool		**RLI**	4.5
Operator		**Rem. Prod. Life**	16.3 yr



Technical Reserves at Sep 1, 2010 (Based on Volumetrics)

	Gross Ult.	Cumulative Production Hist. To Fcst. Start	Fcst. To Ref. Date	Total	Gross Rem.	WI Rem.
Oil (Mbbl)	0.0	0.0	0.0	0.0	0.0	0.0
Gas (MMcf)	468.8	9.1	8.8	18.0	450.8	450.8
Water (Mbbl)	0.0	0.0	0.0	0.0	0.0	0.0

Declines

Segment	Date	Qi	Di (Nom)	Ni	Max	Qf
Gas 1	Jun 2010	300.0 Mcf/d	0.409388 #/yr	0.70	200,000.0 Mcf/d	25.0 Mcf/d

EXHIBIT 4 SAMPLE NOTIFICATION LETTER AND LISTING OF ADDRESSEES

September 1, 2010

Canadian Natural Resources Limited
2500, 855 – 2nd Street SW
Calgary, AB T2P 4J8

Sekani Resources Ltd
1825 Lands End Road
North Saanich, BC V8L 5J2

Meridian Land Services Ltd.
PO Box 118
Millford, NH 03055-0118

Maverick Land Consultants Inc.
310, 6940 Fisher Road SE
Calgary, AB T2H 0W3

Four West Land Consultants Ltd.
510, 206 – 7th Avenue SW
Calgary, AB T2P 0W7

Saskatoon Assets Ltd.
900, 202 – 6th Avenue SW
Calgary, AB T2P 2R9

Wind Fall Resources Ltd.
900, 202 – 6th Avenue SW
Calgary, AB T2P 2R9

Aspect Energy Partnership
181, 715 – 5th Avenue SW
Calgary, AB T2P 2X6

To Whom It May Concern:

Application # YOHO1_100_02
APPLICATION FOR APPROVAL OF A GOOD ENGINEERING PRACTICE AREA FOR THE PRODUCTION OF GAS FROM THE JEAN MARIE FORMATION IN THE PICKELL FIELD

Yoho Resources Inc. (Yoho and its working interest partners) will be submitting an application to the OGC (British Columbia Oil and Gas Commission) for approval of a Good Engineering Practice (GEP) area, for the production of Jean Marie gas in the captioned field.

The application is made pursuant to Section 101 of the Drilling and Production Regulations and the information herein is provided as per OGC Guidelines (12.7) for an application for approval of a Good Engineering Practice Area on the following lands:

094-H-02, Blk E, Units 34-39, 44-49, 56-60, 66-70, 72-75, 78-80, 82-86, 88-90, 94-100
094-H-02, Blk L, Units 4-10, 14, 15, 18-20, 24, 25, 28-30, 40, 50, 56-60, 66-70, 78, 79, 88, 89
094-H-03, Blk, H, Units 34, 35, 44, 45, 51-55, 61-65, 71-75, 81-85, 91-93
094-H-03, Blk I, Units 1-3, 11-13, 21-23, 31-33, 41-43, 51-53, 61-63, 72, 73, 82, 83

The applicant believes approval of the proposed application will allow the most efficient delineation, development and depletion of the resource and increase gas recoveries from the captioned formations.

The OGC requires that mineral owners within the applied-for formation(s) in the area of application and one normal spacing area (4 units) surrounding the area of application receive notice of a GEP application either through Gazette advertising or by direct mailing to the affected parties.

Any concern and/or questions regarding this application are to be directed to the undersigned at (403) 537-1771 ext. 104. You may also send your concern(s) in writing to the undersigned at the address on this letterhead or to the fax number or e-mail address set out below, within 15 working days from the date of this letter. You will then be contacted by the applicant to discuss your concern(s).

Please ensure that any submission includes the application number shown above.

Should your concerns/objections remain unresolved, they will be included as a submission to the application when filed with the OGC.

Please note that the application will be filed with the OGC for processing if no submissions are received within 15 working days of the date of this letter.

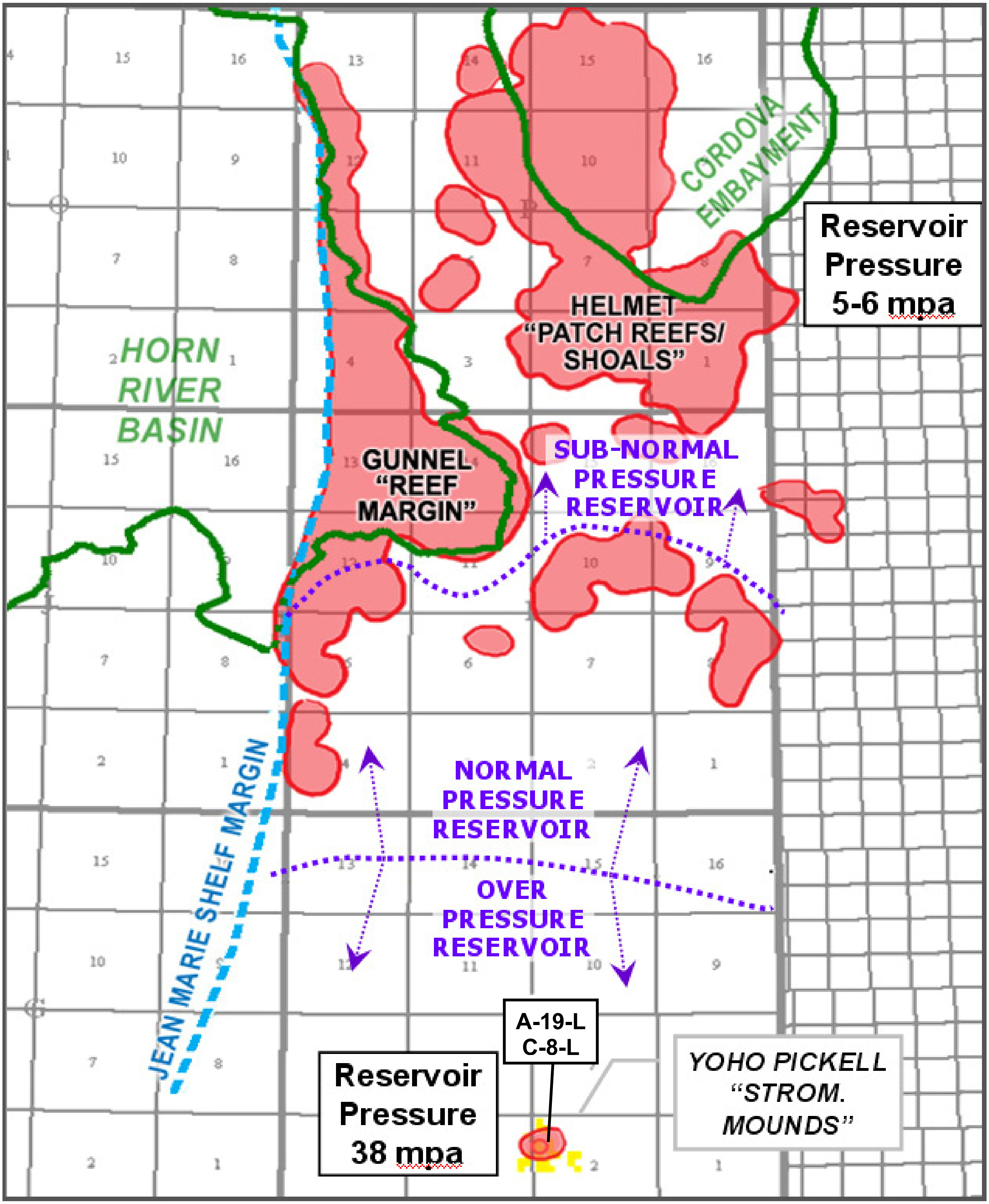
Yours truly,

YOHO RESOURCES INC.

Barry Stobo
VP Engineering & COO

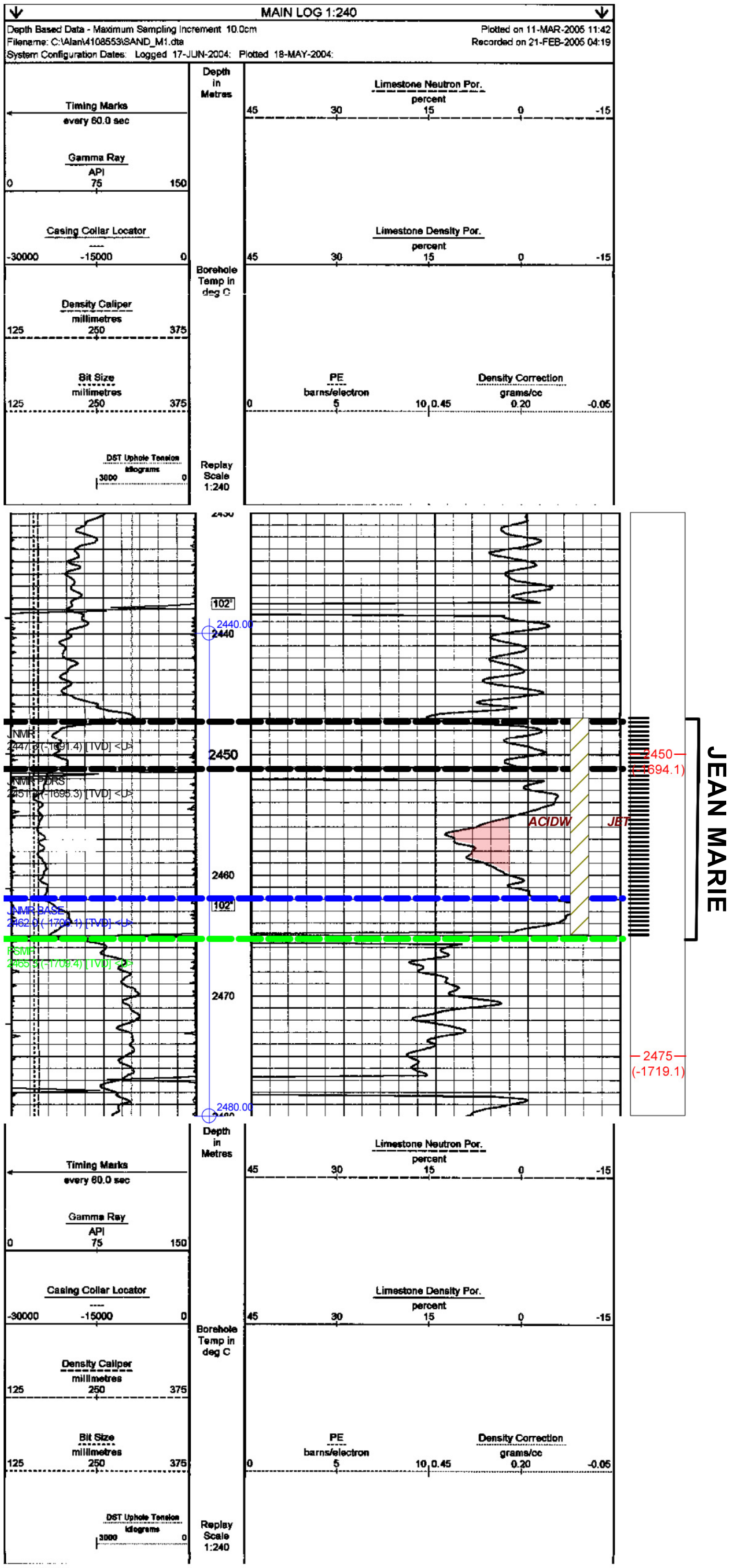
FAX: (403) 537-1775 email: bstobo@yohoresources.ca

EXHIBIT 5 JEAN MARIE: GEOLOGICAL DATA


HORN RIVER BASIN
CORDOVA EMBAYMENT
Reservoir Pressure 5-6 mpa
HELMET "PATCH REEFS/ SHOALS"
GUNNEL "REEF MARGIN"
SUB-NORMAL PRESSURE RESERVOIR
NORMAL PRESSURE RESERVOIR
OVER PRESSURE RESERVOIR
JEAN MARIE SHELF MARGIN
A-19-L
C-8-L
Reservoir Pressure 38 mpa
YOHO PICKELL "STROM. MOUNDS"

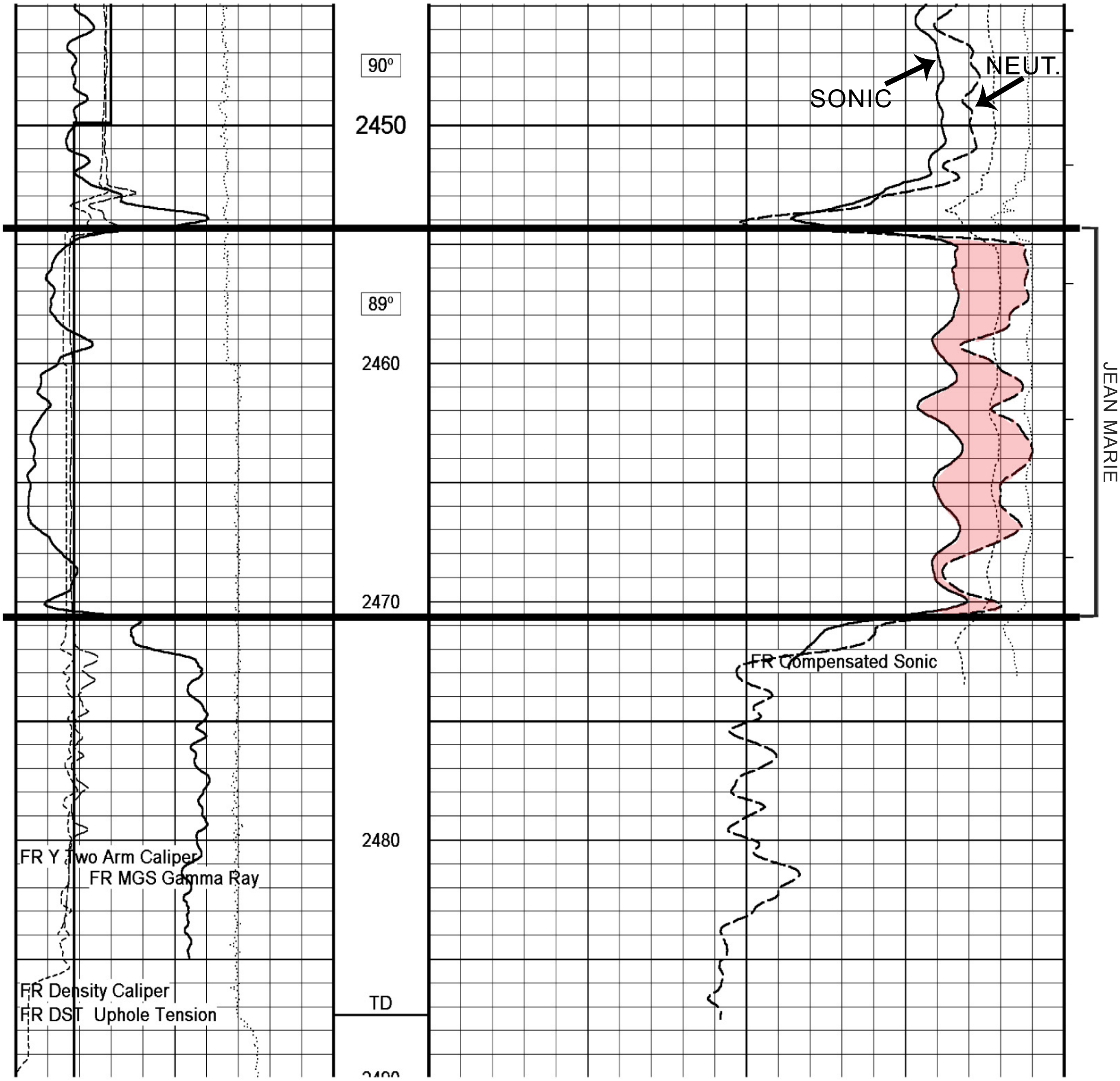
00/A-019-L/094-H-02/0

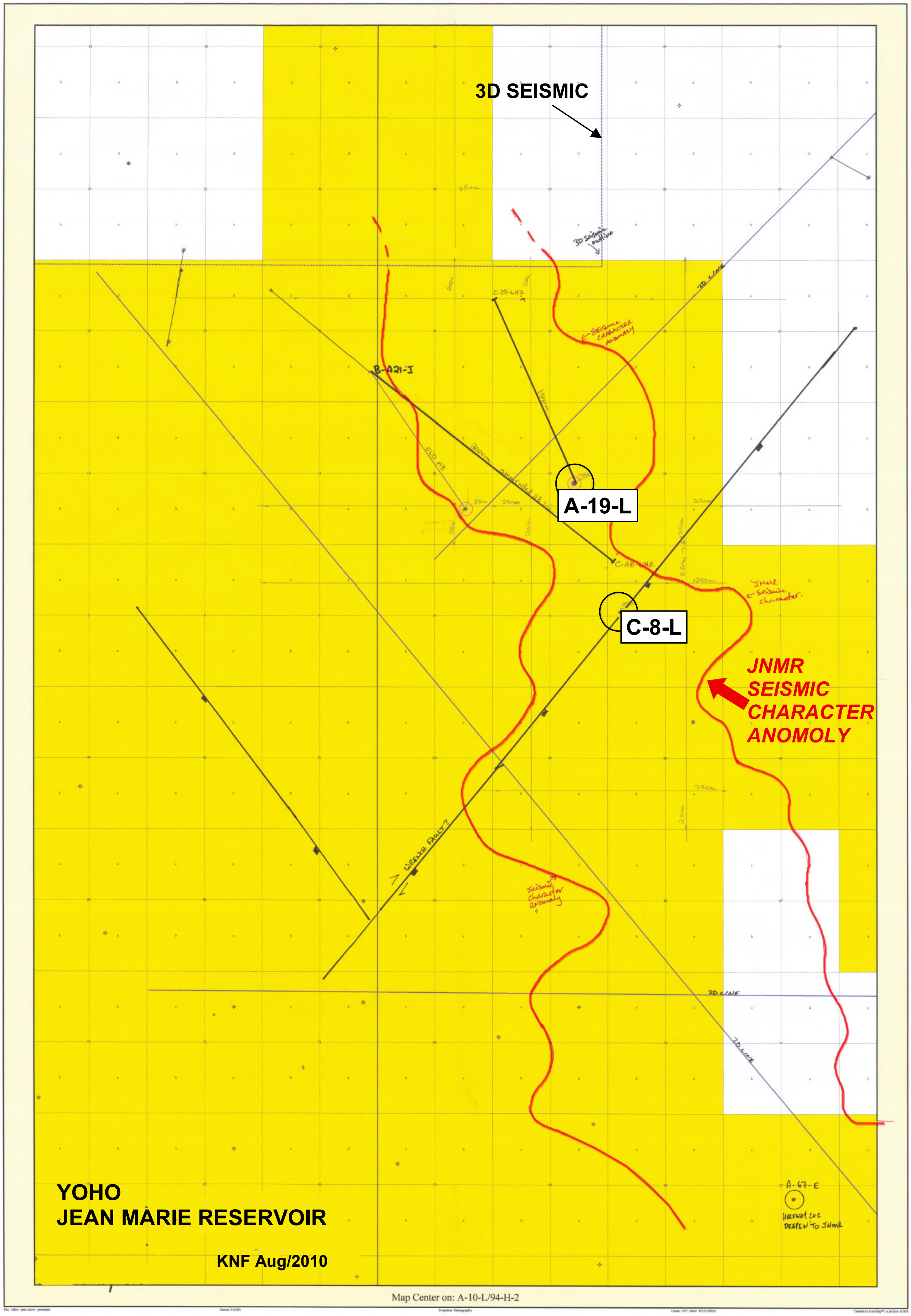
KB: 755.9 m RR: 2005-02-19
TD: 2986.0 m [TVD] FormTD: SLVP
Mode: Susp Fluid: N/A
YOHO RESOURCES INC.



DST Information

C-8-L/94-H-2


90°
SONIC
NEUT.
2450
89°
2460
JEAN MARIE
2470
FR Compensated Sonic
2480
FR Y Two Arm Caliper
FR MGS Gamma Ray
FR Density Caliper
FR DST Uphole Tension
TD



YOHO
JEAN MARIE RESERVOIR

KNF Aug/2010

Map Center on: A-10-L/94-H-2

REPORTED INTERVAL 2453.0m - 2471.0m

ADJUSTED INTERVAL 2454.3m - 2472.3m

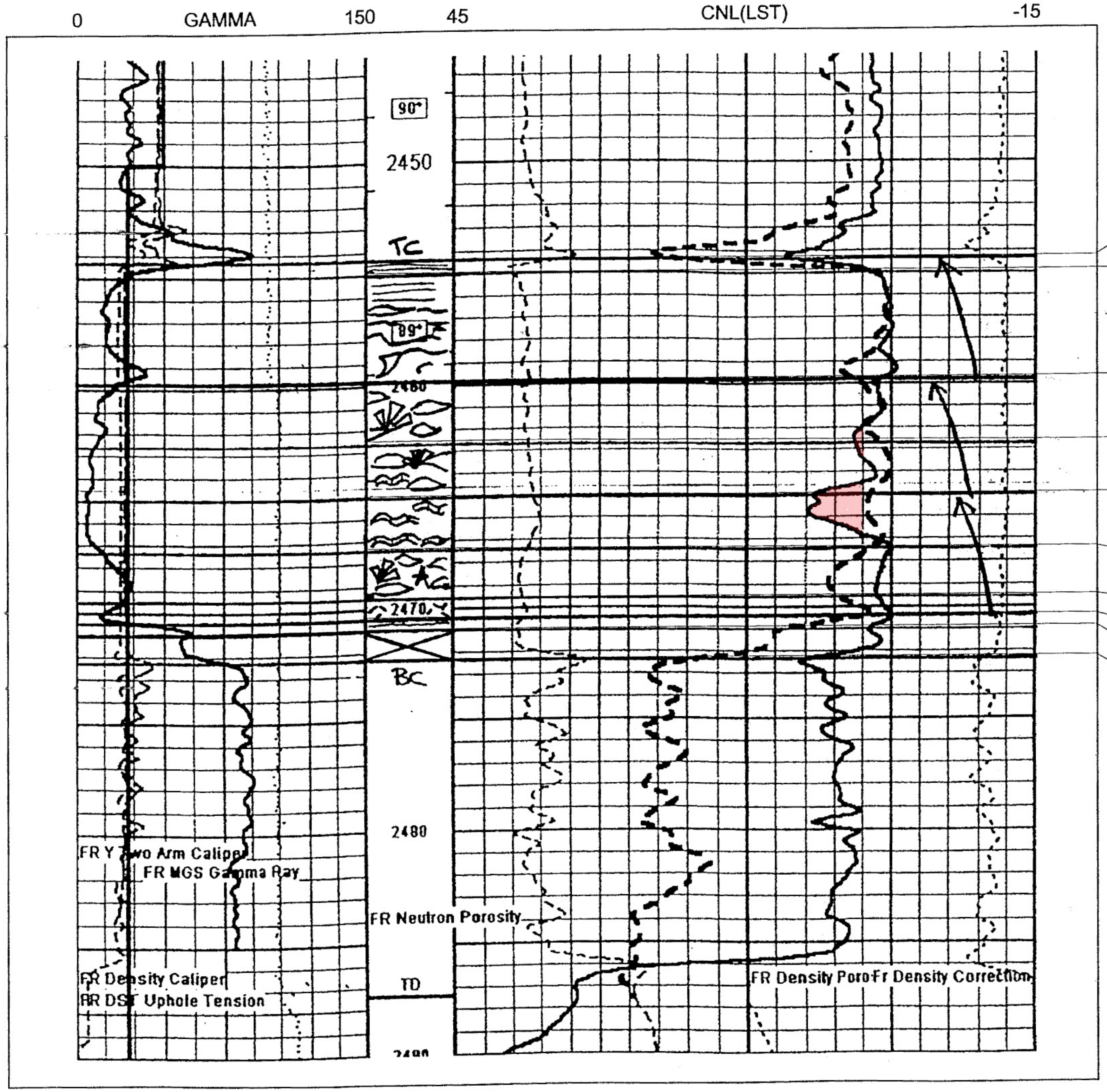
SLABBED: Y ■ N ☐

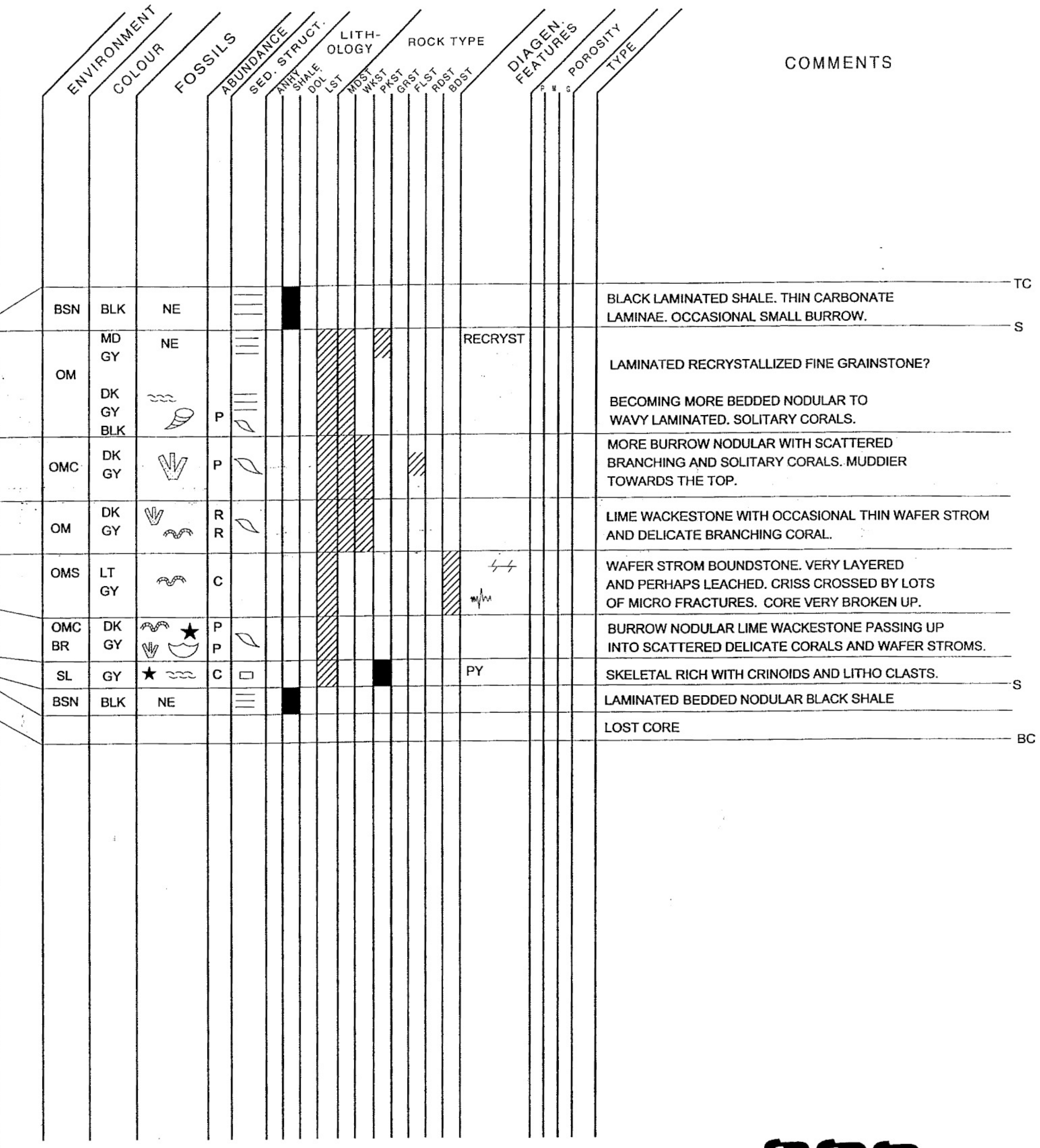
QUALITY: GOOD

PRODUCTION

FORMATION JEAN MARIE MEMBER

WELL LOCATION C-8-L/94-H-2





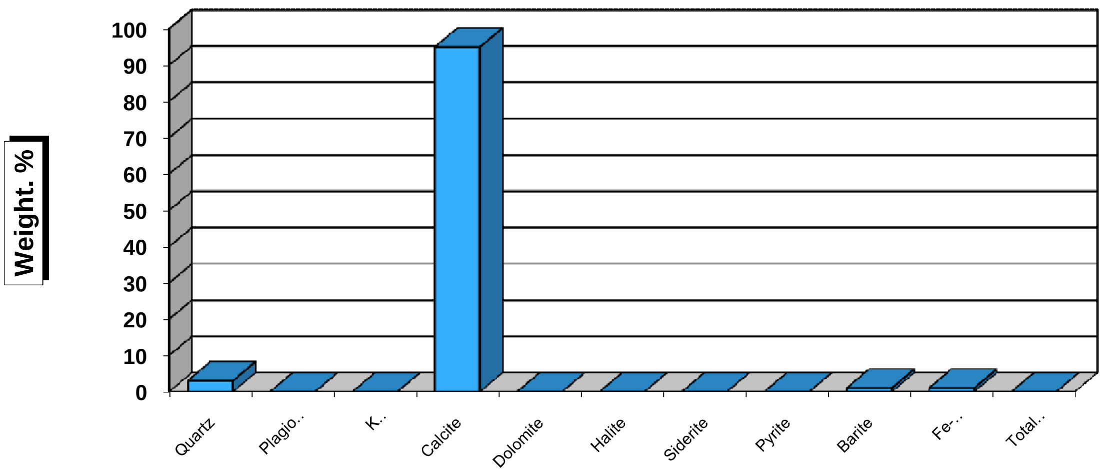
ENVIRONMENT	COLOUR	FOSSILS	ABUNDANCE	SED. STRUCT.	LITHOLOGY				ROCK TYPE							DIAGEN. FEATURES	POROSITY			TYPE	COMMENTS
					ANHY	SHALE	DOL	LST	MDST	WKST	PKST	GRST	FLST	RDST	BDST		P	M	G		
BSN	BLK	NE		≡		■															BLACK LAMINATED SHALE. THIN CARBONATE LAMINAE. OCCASIONAL SMALL BURROW.
OM	MD GY DK GY BLK	NE	P	≡				▨	▨		▨					RECRYST					LAMINATED RECRYSTALLIZED FINE GRAINSTONE? BECOMING MORE BEDDED NODULAR TO WAVY LAMINATED. SOLITARY CORALS.
OMC	DK GY		P					▨	▨	▨			▨								MORE BURROW NODULAR WITH SCATTERED BRANCHING AND SOLITARY CORALS. MUDDIER TOWARDS THE TOP.
OM	DK GY		R R					▨	▨	▨											LIME WACKESTONE WITH OCCASIONAL THIN WAFER STROM AND DELICATE BRANCHING CORAL.
OMS	LT GY		C					▨							▨						WAFER STROM BOUNDSTONE. VERY LAYERED AND PERHAPS LEACHED. CRISS CROSSED BY LOTS OF MICRO FRACTURES. CORE VERY BROKEN UP.
OMC BR	DK GY	★	P P					▨													BURROW NODULAR LIME WACKESTONE PASSING UP INTO SCATTERED DELICATE CORALS AND WAFER STROMS.
SL	GY	★	C	▭				▨			■					PY					SKELETAL RICH WITH CRINOIDS AND LITHO CLASTS.
BSN	BLK	NE		≡		■															LAMINATED BEDDED NODULAR BLACK SHALE
																					LOST CORE

X-RAY DIFFRACTION ANALYSIS

Bulk Mineralogy Analysis

COMPANY:	YOHO RESOURCES INC.	**File #: 52135-10-0065**
WELL / LOCATION:	YOHO PICKELL c-8-L 94-H-2	**Analyst: S.H**
SAMPLE:	SPA-17	**Date: 05/20/2010**
DEPTH:	2464.09 m	

		BULK COMPOSITION (WEIGHT %)
Quartz	(SiO_2)	3
Plagioclase	($NaAlSi_3O_8$ - $CaAl_2Si_2O_8$)	Trace
K Feldspar	($KAlSi_3O_8$)	0
Calcite	($CaCO_3$)	95
Dolomite	($CaMg[CO_3]_2$)	0
Halite	($NaCl$)	0
Siderite	($FeCO_3$)	0
Pyrite	(FeS_2)	0
Barite	($BaSO_4$)	1
Fe-Dolomite	($Ca[Fe, Mg][CO_3]_2$)	1
Total Clay		0
TOTAL		**100**



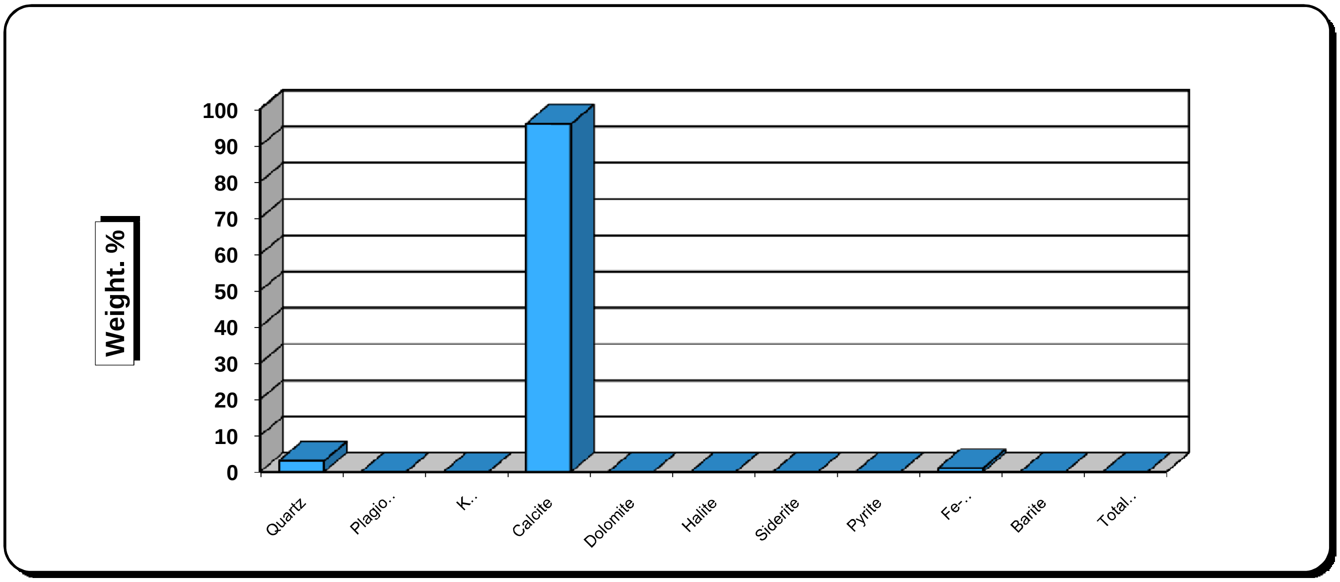
Due to inherent limitations in X-ray diffraction quantification, results must be considered semi-quantitative.

X-RAY DIFFRACTION ANALYSIS

Bulk Mineralogy Analysis

COMPANY:	YOHO RESOURCES INC.	**File #: 52135-10-0065**
WELL / LOCATION:	YOHO PICKELL c-8-L 94-H-2	**Analyst: S.H**
SAMPLE:	SP-23	**Date: 05/20/2010**
DEPTH:	2465.22 m	

		BULK COMPOSITION (WEIGHT %)
Quartz	(SiO_2)	3
Plagioclase	($NaAlSi_3O_8$ - $CaAl_2Si_2O_8$)	Trace
K Feldspar	($KAlSi_3O_8$)	0
Calcite	($CaCO_3$)	96
Dolomite	($CaMg[CO_3]_2$)	0
Halite	($NaCl$)	0
Siderite	($FeCO_3$)	0
Pyrite	(FeS_2)	0
Fe-Dolomite	($Ca[Fe, Mg][CO_3]_2$)	1
Barite	($BaSO_4$)	Trace
Total Clay		0
TOTAL		**100**



Due to inherent limitations in X-ray diffraction quantification, results must be considered semi-quantitative.


c-8-L/94-H-2

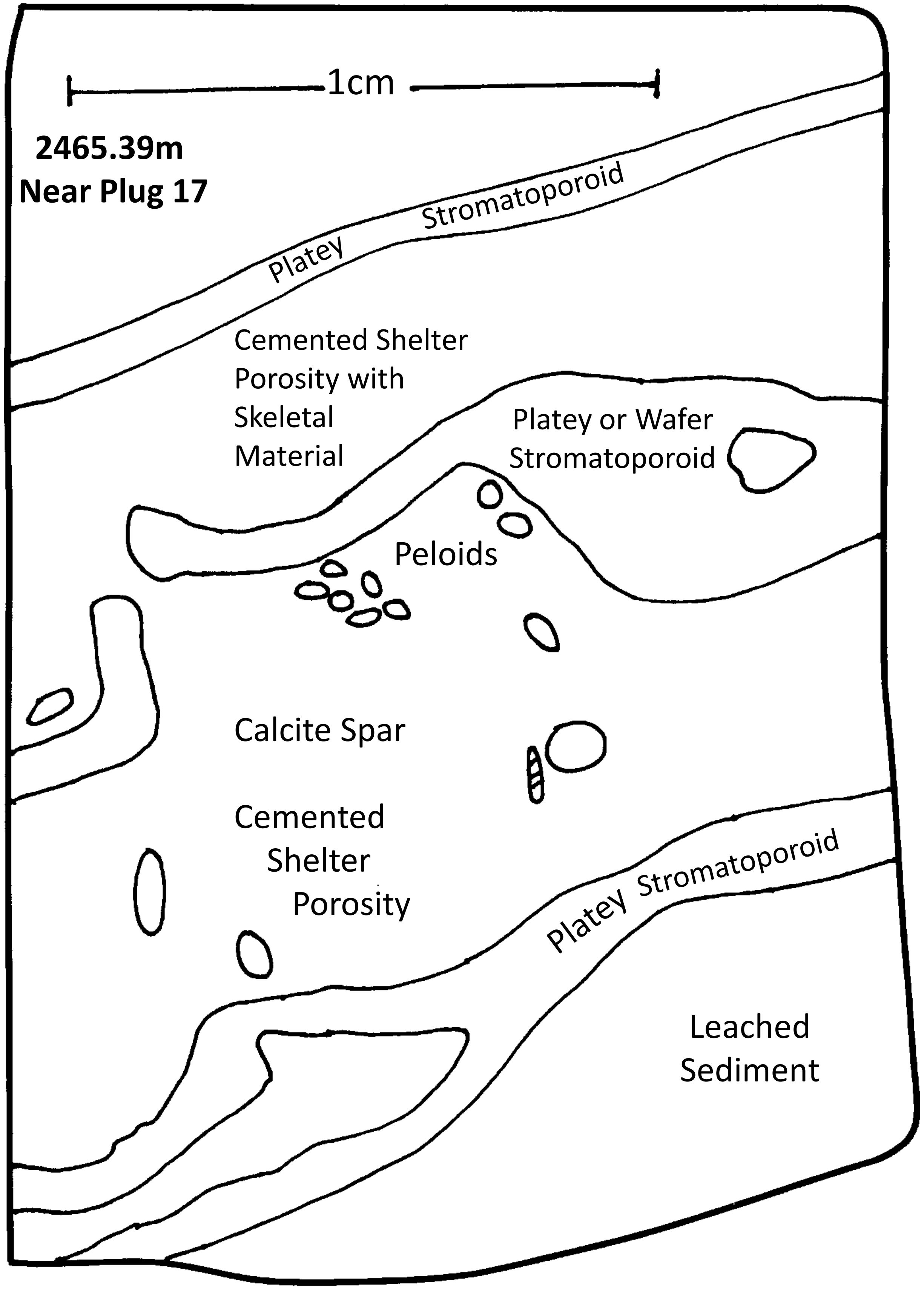

1cm
2465.39m
Near Plug 17
Platey Stromatoporoid
Cemented Shelter Porosity with Skeletal Material
Platey or Wafer Stromatoporoid
Peloids
Calcite Spar
Cemented Shelter Porosity
Platey Stromatoporoid
Leached Sediment

PLATE 1

CORE LABORATORIES

Company : YOHO RESOURCES INC.
Well : YOHO PICKELL c-8-L 94-H-2
Location : c-8-L 94-H-2
Province : BRITISH COLUMBIA

Field : PICKELL
Formation : JEAN MARIE
Coring Equip : DIAMOND
Coring Fluid : WATER BASE MUD

File No. : 52131-10-0065
Date : 2010-10-0065
Analysts : DJB
Core Dia : 100 mm

CORE ANALYSIS RESULTS

SAMPLE NUMBER		DEPTH m	INTVL REP m	SAMPLE LENGTH m	SPOT DEPTH m	PERMEABILITY			CAPACITY (MAXIMUM) Kair mD-m	POROSITY (HELIUM) fraction	CAPACITY (HELIUM) ø-m	BULK DENSITY kg/m3	GRAIN DENSITY kg/m3	DESCRIPTION
						(MAXIMUM) Kair mD	(90 DEG) Kair mD	(VERTICAL) Kair mD						
CORE NO.1 2453.00 - 2471.00 m (CORE RECEIVED 16.70 m) (15 BOXES)														
NA		2453.00- 2454.02	1.02											sh
FD	1	2454.02- 2454.64	0.62	0.22		0.01	<0.01	<0.01	0.006	0.010	0.006	2670	2700	ss vf calc carb lam
PFD	2	2454.64- 2455.20	0.56	0.08		0.03	0.03	<0.01	0.017	0.010	0.006	2680	2710	ss vf calc pyr
FD	3	2455.20- 2456.29	1.09	0.17		0.01	0.01	<0.01	0.011	0.014	0.015	2670	2710	ss vf calc lam
FD	4	2456.29- 2456.82	0.53	0.11		0.02	0.01	<0.01	0.011	0.010	0.005	2670	2690	ls i sdy
FD	5	2456.82- 2457.99	1.17	0.14		<0.01	<0.01	<0.01		0.011	0.013	2670	2700	ls i sdy
FD	6	2457.99- 2459.10	1.11	0.14		0.05	0.03	<0.01	0.056	0.013	0.014	2680	2710	ls i sdy
FD	7	2459.10- 2459.42	0.32	0.08		0.02	0.02	<0.01	0.006	0.012	0.004	2660	2690	ls i
PFD	8	2459.42- 2460.19	0.77	0.12		0.04	<0.01	<0.01	0.031	0.016	0.012	2650	2700	ls i
FD	9	2460.19- 2460.89	0.70	0.16		0.06	0.03	<0.01	0.042	0.026	0.018	2640	2710	ls i
PFD	10	2460.89- 2461.30	0.41	0.15		0.01	<0.01	<0.01	0.004	0.036	0.015	2630	2730	ls i
FD	11	2461.30- 2461.85	0.55	0.19		0.15	0.07	0.03	0.083	0.042	0.023	2600	2720	ls i
FD	12	2461.85- 2462.38	0.53	0.12		0.18	0.09	<0.01	0.095	0.030	0.016	2620	2700	ls i
FD	13	2462.38- 2462.94	0.56	0.14		0.39	0.17	0.01	0.218	0.030	0.017	2620	2710	ls i
FD	14	2462.94- 2463.53	0.59	0.17		0.13	0.10	0.01	0.077	0.019	0.011	2650	2700	ls i
FD	15	2463.53- 2463.93	0.40	0.08		1.26	1.01	0.04	0.504	0.051	0.020	2570	2710	ls i
FD	16	2463.93- 2464.09	0.16	0.05		*	*	*		0.095	0.015	2450	2710	ls i frac
SPA	17	2464.09- 2464.17	0.08		2461.12	0.12			0.010	0.056	0.004	2560	2710	ls i
PFD	18	2464.17- 2464.39	0.22	0.08		17.7	12.1	3.55	3.894	0.106	0.023	2440	2720	ls i lam

CORE LABORATORIES

Company : YOHO RESOURCES INC.
Well : YOHO PICKELL c-8-L 94-H-2
Location : c-8-L 94-H-2
Province : BRITISH COLUMBIA

Field : PICKELL
Formation : JEAN MARIE
Coring Equip : DIAMOND
Coring Fluid : WATER BASE MUD

File No. : 52131-10-0065
Date : 2010-10-0065
Analysts : DJB
Core Dia : 100 mm

CORE ANALYSIS RESULTS

SAMPLE NUMBER	DEPTH m	INTVL REP m	SAMPLE LENGTH m	SPOT DEPTH m	PERMEABILITY			CAPACITY (MAXIMUM) Kair mD-m	POROSITY (HELIUM) fraction	CAPACITY (HELIUM) ø-m	BULK DENSITY kg/m3	GRAIN DENSITY kg/m3	DESCRIPTION
					(MAXIMUM) Kair mD	(90 DEG) Kair mD	(VERTICAL) Kair mD						
FD 19	2464.39- 2464.57	0.18	0.07		*	*	8.53		0.105	0.019	2440	2730	ls i frac
SPA 20	2464.57- 2464.98	0.41		2461.92	0.07			0.029	0.068	0.028	2530	2720	ls i
SPA 21	2464.98- 2465.12	0.14		2462.07	0.07			0.010	0.069	0.010	2520	2710	ls i
PFD 22	2465.12- 2465.22	0.10	0.07		*	29.8	*		0.109	0.011	2420	2720	ls i frac
SP 23	2465.22- 2465.38	0.16		2462.33	*				0.060	0.010	2550	2710	ls i frac
PFD 24	2465.38- 2465.51	0.13	0.08		*	119.	*		0.106	0.014	2420	2710	ls i frac
FD 25	2465.51- 2465.85	0.34	0.08		*	*	25.3		0.101	0.034	2450	2730	ls i frac
FD 26	2465.85- 2466.32	0.47	0.18		0.23	0.08	<0.01	0.108	0.024	0.011	2700	2760	ls i
FD 27	2466.32- 2466.90	0.58	0.20		0.49	0.11	0.03	0.284	0.022	0.013	2660	2720	ls i
FD 28	2466.90- 2467.48	0.58	0.11		0.02	0.02	<0.01	0.012	0.028	0.016	2640	2710	ls i
FD 29	2467.48- 2468.04	0.56	0.15		0.18	0.04	<0.01	0.101	0.034	0.019	2620	2720	ls i
FD 30	2468.04- 2468.61	0.57	0.15		0.11	0.07	<0.01	0.063	0.038	0.022	2620	2720	ls i
FD 31	2468.61- 2469.70	1.09	0.14		0.02	<0.01	<0.01	0.022	0.008	0.009	2670	2690	ls i
LC	2469.70- 2471.00	1.30											Lost core

Note: Highlighted portions (red outline) have dubious permeability due to fractures.