

WORLD-WIDE PETROLEUM CONSULTING

EXPLORATION  
ASSESSMENT  
OF  
TIGHT GAS PLAYS  
NORTHEASTERN  
BRITISH COLUMBIA



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# EXPLORATION ASSESSMENT OF TIGHT GAS PLAYS NORTHEASTERN BRITISH COLUMBIA

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EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

for

**British Columbia Ministry of Energy and Mines  
Resource Development Division  
New Ventures Branch**

March, 2003





## EXECUTIVE SUMMARY

Tight gas reservoirs, defined as those exhibiting subeconomic reservoir quality by normal production standards, are widespread throughout northeastern British Columbia. Although most commonly associated with the Deep Basin area, they occur also in the Foothills, and in the Plains north of the Peace River Block.

In this report, we describe tight gas reservoirs, production, and potential in fifteen distinct stratigraphic intervals. Large-scale production currently takes place from three major play areas:

- **Deep Basin** – stacked Mesozoic clastic reservoirs, each regionally extensive and gas-saturated, produce from isolated stratigraphic “sweet spots”, featuring conventional reservoir quality.
- **Foothills** – carbonate and clastic reservoirs in the deep Foothills at Bullmoose-Sukunka, and in the outer Foothills to the north, in the Beg-Jedney-Bubbles areas, produce prolifically where natural fractures enhance deliverability from tight- to moderate-quality rocks.
- **Northern Plains** – regionally-extensive Devonian carbonates are naturally fractured to a relatively minor degree, but produce economically with modern drilling and completion techniques.

Exploitation of tight gas reservoirs is far more advanced in the United States than it is in Canada. Case histories from analogue basins, particularly in Cretaceous strata of various U.S. Rocky Mountain Basins, are useful in developing exploitation strategies for tight gas reservoirs in B.C. There are two important exploration/exploitation strategies which can be pursued more systematically in B.C.:

- Pursuit of extremely thick basin-centered gas sandstones
- Detection and exploitation of natural fracture “sweet spots” in settings with little structural deformation

Application of cutting-edge drilling and completions technologies is also critical to successfully exploiting tight gas reservoirs. Key strategies that are being used now, but which offer additional upside, include:

- Directional and horizontal drilling
- Underbalanced drilling
- Advanced fracture stimulation.



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# INTRODUCTION

Petrel Robertson Consulting Ltd. undertook an assessment of “tight gas” production and exploration potential in British Columbia in early 2003, for the British Columbia Ministry of Energy and Mines, Resource Development Division, New Ventures Branch. This report summarizes the project, and addresses several key areas:

- Definition of tight gas, and overview of its history and recent development in British Columbia;
- Geology and reservoir characteristics of major tight gas units in B.C.;
- Analysis of future exploration and development potential;
- Comparison with analogue basins;
- Application of current exploitation strategies, including modern drilling and completions technologies, to exploit tight gas reservoirs

This project is a regional overview for the purpose of assessing tight gas potential and highlighting opportunities. Isopach maps have been generated by direct interpretation of well logs from selected wells, to show regional patterns. Test, production, and reserves data are derived from commercial databases and government documents; we have not examined individual well records for this information.

## DEFINITIONS

“Tight gas” lacks a formal definition, and usage of the term varies considerably. Law and Curtis (2002) defined low-permeability (tight) reservoirs as having permeabilities less than 0.1 millidarcies. Many explorationists think of tight or low-permeability reservoirs as occurring only within basin-centred, or deep basin settings. Law (2002) confirmed that low-permeability reservoirs characterize basin-centred gas accumulations, but can also occur elsewhere.

For the purposes of this study, and to be as inclusive as possible, we define “tight gas” reservoirs as those that are regionally extensive, and typically of sub-economic reservoir quality by normal completion and production standards. Although much of this rock fits the Law and Curtis definition ( $K < 0.1$  md), we have not adhered strictly to this cut-off. Much, but not all, tight gas is found within the Deep Basin, where it occurs as regionally pervasive, gas-saturated, abnormally

pressured accumulations lacking downdip water contacts. Isolated “sweet spots” within tight gas units may feature conventional (economic) reservoir quality; these account for most current Deep Basin production.

Fractured shale-gas systems have been defined using a distinct set of parameters by Curtis (2002), and are not considered in this assessment.

## TIGHT GAS REGIONS IN BRITISH COLUMBIA

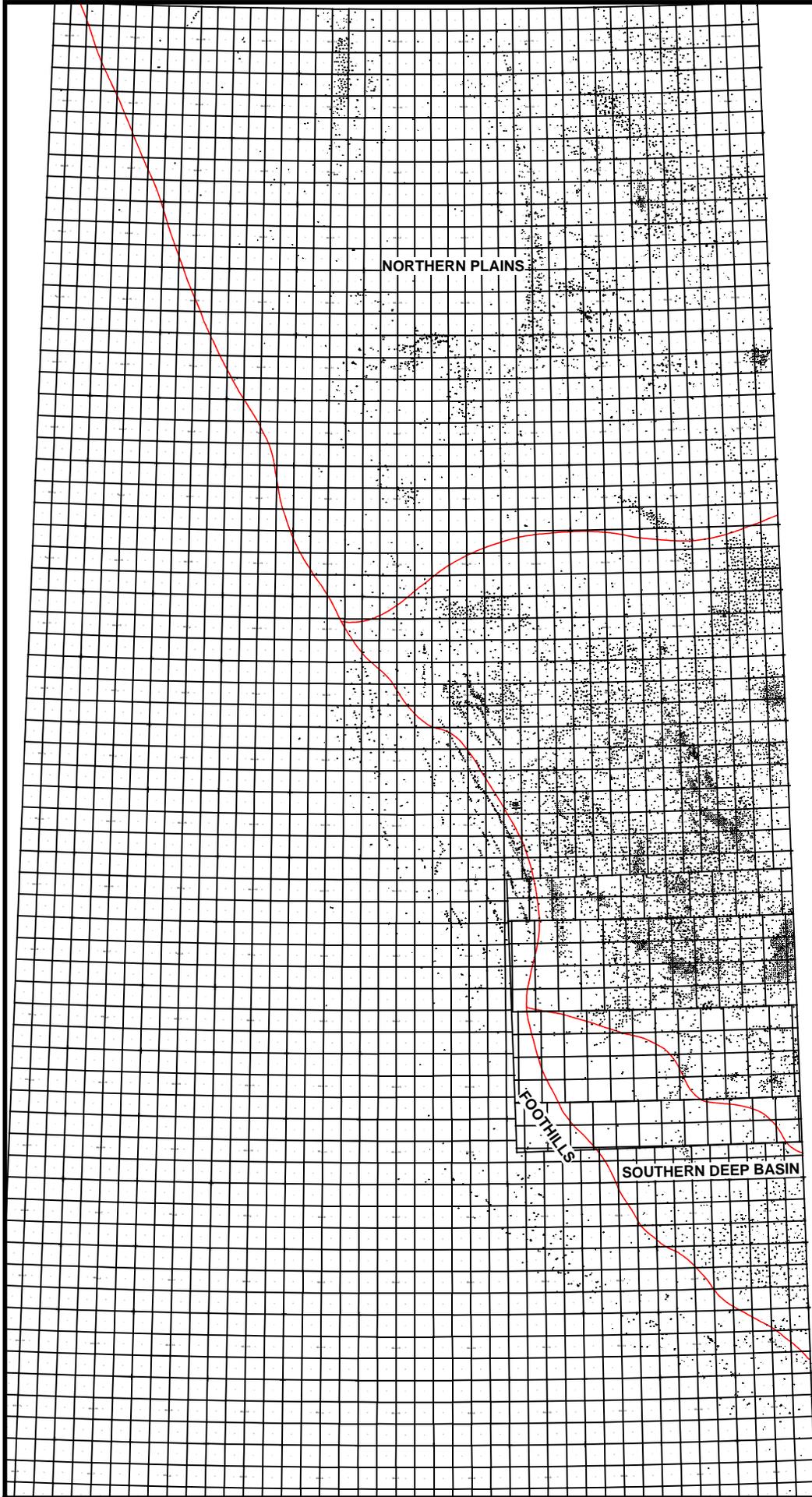
Tight gas reservoirs occur throughout northeastern British Columbia. Three distinct regions can be recognized, based upon structural and stratigraphic characteristics (Map 1).

1. **Deep Basin** – Characterized by stacked Mesozoic clastic reservoirs, each regionally extensive and gas-saturated, containing abnormally-pressured gas accumulations lacking downdip water contacts. The updip (northeastern) boundary of the Deep Basin varies throughout the stratigraphic column, as each reservoir unit has its own updip edge.
2. **Foothills** – Tight gas reservoirs of various ages and types produce where structural deformation creates extensive natural fracture systems. To the east, reservoir quality tends to be more conventional, and fracturing plays a lesser role.
3. **Northern Plains** – Laterally extensive tight gas reservoirs produce where relatively subtle natural fractures can be exploited with horizontal drilling and advanced stimulation techniques. Only one unit, the Jean Marie platform carbonate, is an established producer. The Jean Marie appears to be a geographically-distinct basin-centred gas accumulation.

## TIGHT GAS EXPLORATION AND EXPLOITATION

*Current Situation* – Until recently, Canadian tight gas reservoirs have been regarded as uneconomic, and have received relatively little attention. Masters (1979) tabulated up to 440 TCF (12,500 e<sup>9</sup>m<sup>3</sup>) of recoverable tight gas resource in the western Canadian Deep Basin, assuming substantial price escalation and technological advances over time. Neither price nor technology has advanced sufficiently to recognize more than a small fraction of these volumes. Today, British Columbia Deep Basin gas reserves total about 100 e<sup>9</sup>m<sup>3</sup>, and occur almost exclusively in reservoir “sweet spots”. Gas in Deep Basin tight sands is regarded as a future possible resource, not as reserves.

Outside of the Deep Basin (as recognized by Masters), fractured tight carbonates have been prolific producers along the Bullmoose-Sukunka Foothills structural trend since the 1970’s. Natural fracturing also plays a role in productivity of tight

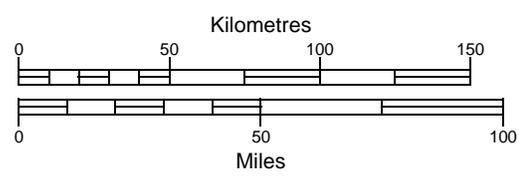


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**TIGHT GAS REGIONS,  
NORTHEASTERN  
BRITISH COLUMBIA**

GEOLOGIST: BRAD J. HAYES      1:2 500 000      MAP 1  
DRAWN BY: KRISTA WALKER      FEBRUARY 2003  
PETREL ROBERTSON CONSULTING LTD.



to marginal reservoirs in the outer Foothills to the north, at Beg-Jedney-Bubbles. In addition, horizontal drilling has accessed large gas accumulations within tight platformal carbonates of the Jean Marie Member in the northern B.C. Plains. Discovered gas in place was estimated at 11.6 e<sup>9</sup>m<sup>3</sup>, with an additional 24.0 e<sup>9</sup>m<sup>3</sup> to be found; however, recent discoveries will likely increase these numbers.

*Exploration and Exploitation* – Today, most B.C. tight gas exploration and exploitation activity takes place within the context of the three play areas discussed above:

- Stratigraphic mapping to discover Deep Basin “sweet spots”, featuring conventional reservoir quality within coarse-grained clastics. Tight sands encompassing the sweet spots contribute some gas as pressures are drawn down by production.
- Structural mapping of Bullmoose-Sukunka fractured reservoirs, with emphasis on delineating structural configurations that optimize reservoir fracturing. Outer Foothills fractured reservoirs at Beg-Jedney-Bubbles are also targeted along structural culminations.
  - recent discoveries suggest that similar play models may be pursued successfully in other low-permeability reservoir units
- Horizontal drilling in Jean Marie platformal carbonates
  - EnCana is now extending this play into new, previously uneconomic areas, using economies of scale, and drilling and completion technology advances



# GEOLOGICAL REVIEW OF TIGHT GAS RESERVOIR UNITS

## **CARDIUM FORMATION** (Turonian – Upper Cretaceous)

### Stratigraphy and Distribution

The Cardium is a northeasterly-prograding shoreface/alluvial plain complex, derived from highlands in the B.C. interior. It is overlain by a thinner progradational complex (Muskiki/Marshybank/Badheart Formations), and both are encased within thick marine shales of the Smoky Group (Cross-section CRD-CRD'). Cardium stratigraphy and sedimentology has been documented extensively in Alberta, but relatively little work has been done in northeastern B.C. (Plint and Hart, 1988; Hart and Plint, 1990).

Cardium strata crop out along the eastern margin of the Foothills in 93I and 93P, and reach their northern limit across the southern margin of the Peace River Block (Map 2; Photo 1-1). In the subsurface, they occur in eastern 93P and the northeastern corner of 93I, generally at depths of 1000 metres or less.

Cardium shoreface sandstones occur as sandier- and coarsening-upward successions, grading up from Kaskapau marine shales, and capped by backshore to continental fine-grained clastics (Core log 1; Photo 2-1). The shoreface unit is termed the Kakwa Member, and the continental unit the Musreau Member (Cross-section CRD-CRD'). Relatively thin, reservoir-quality sandstones may occur in transgressive units capping the Musreau; these are productive at Kakwa (Twp. 62-64, Rge. 3-5W6, Alberta), but are not volumetrically significant in B.C.

### Reservoir Description

Cardium sandstones range from silty to very fine-grained in the lower to middle shoreface, and grade or pass abruptly up to fine- to medium-grained sandstone in the upper shoreface to foreshore (Photos 2-2, 2-3). In places, the upper shoreface may become conglomeratic (Photo 1-1), but such occurrences are rare and not laterally extensive. Cardium sandstones are typically quartz-chert litharenites, with minor sedimentary and metamorphic rocks fragments, and traces of feldspar (Photo 3-1; Appendix 4).

Porosity values in middle shoreface sandstones are generally less than 10%, and permeabilities rarely exceed 0.1 md (core analysis plot, Core log 1). In the upper shoreface, porosities are only marginally higher, but permeabilities may reach 1 md. Compaction has significantly reduced reservoir quality, as Cardium strata

were buried much more deeply prior to Tertiary uplift and erosion (Photo 3-1). Conventional reservoir quality may be found in conglomerates if they are sorted sufficiently well, but no examples have been documented in B.C. to date.

Net clean sandstone thicknesses were mapped using a 75% clean gamma ray cut-off, without regard for porosity (Map 2, Cross-section CRD-CRD'). Cardium sandstones are regionally extensive, and range from about 15 to 50 metres thick.

### Hydrocarbon Occurrences

Well b-A4-D/93-P-8, which was completed for gas at a rate of 2100 m<sup>3</sup>/d, is the only Cardium producer in British Columbia. Drillstem tests have recovered only mud, and indicate low reservoir permeabilities within the Deep Basin; to the northeast, water recoveries and better-quality reservoirs are evident (Map 2). Most Cardium production in Alberta lies to the east and southeast of Map 2.

Compared to other Deep Basin units, the Cardium has not been tested extensively. No reservoir “sweet spots” have been identified in B.C., and no systematic effort to test tight gas potential has been made.

## **DUNVEGAN FORMATION (Cenomanian – Upper Cretaceous)**

### Stratigraphy and Distribution

Dunvegan strata form a large, southeasterly-prograding wedge of deltaic and shoreface sediments, which originated in far northern B.C. and the territories, and reached a distal edge in west-central Alberta (Fig. 1). It lies between marine shales of the Shaftesbury Formation below and the Kaskapau Formation above. Lower Kaskapau sandstones termed the Doe Creek, Howard Creek, and Pouce Coupe, are considered to be part of the Dunvegan complex in this review (Photo 1-2).

The Dunvegan has been mapped in outcrop by Stott (1982), and in the subsurface by several workers; Plint (2000) produced a comprehensive regional analysis. Most of this work has focused on sequence stratigraphic or allostratigraphic architecture, however, with little attention paid to reservoir quality and distribution.

Dunvegan outcrop and subsurface distribution in northeastern B.C. is very similar to that of the Cardium (Map 3). The entire unit ranges up to 300 metres thick, with individual sands as thick as 25 metres. It is buried up to 2500 metres deep in 93I, and over 3000 metres deep in adjacent Alberta (Cross-section DUN-DUN').

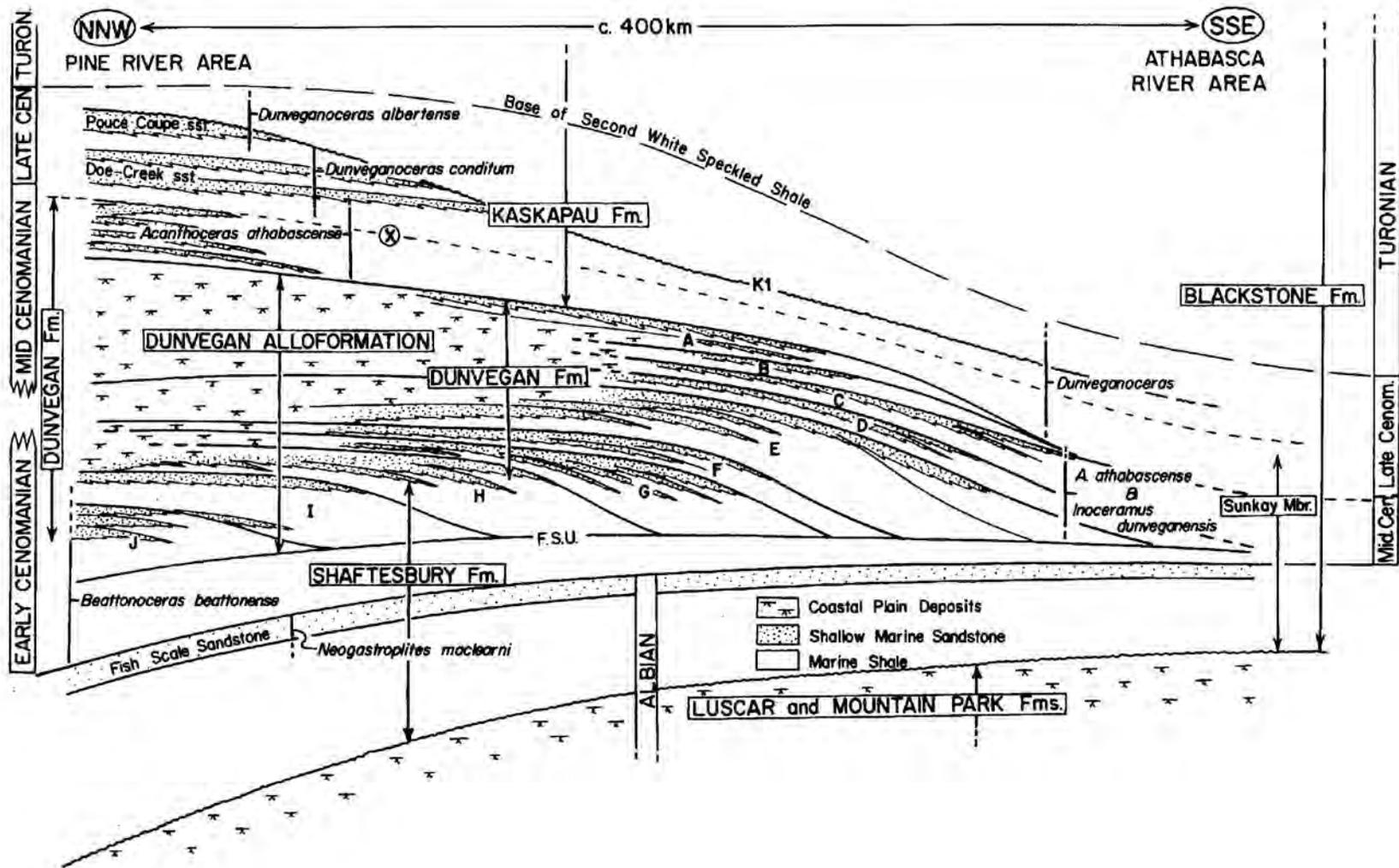


Fig. 1. Schematic N-S cross-section, Dunvegan Formation. Note shallow marine sandstones and channelized coastal plain deposits in each of allomembers A to J, as well as thin shallow marine sandstone units within overlying Kaskapau Formation (from Plint, 2000).

Dunvegan sandstones were deposited in deltaic to shoreface settings at the seaward limit of several regressive subunits (allomembers of Plint (2000)), and in associated distributary channels and valley fills. Plint (2000) mapped regional paleogeography and generalized sand distribution for each allomember, but detailed reservoir isopach maps have not been published.

### Reservoir Description

Dunvegan reservoirs in the B.C. subsurface have not been described in detail, and few cores are available. Regional outcrop work demonstrates that the Dunvegan is conglomeratic in outcrop to the north, but is dominated by fine- to medium-grained sandstones to the south (Stott, 1982; Plint and Hart, 1988). Bhattacharya and Walker (1992) described very fine- to medium-grained reservoir sandstones in adjacent west-central Alberta, deposited in a variety of fluvial, estuarine, deltaic, and shoreface environments.

Dunvegan pools in Alberta lie in a broad arc extending from Twp. 60, Rge. 21W5, northwest to Twp. 78, Rge. 13W6. They exhibit conventional reservoir quality, although in the northwest, this quality is found primarily in thin Kaskapau sandstone units. Southwestward, burial compaction has degraded reservoir quality significantly. At Lynx (Twp. 61-9W6, Map 3), thick deltaic sandstones appear to have poor reservoir quality, but performance has likely been enhanced by fracturing associated with Laramide fault movements (Cross-section DUN-DUN').

A net sandstone map was not made for the Dunvegan. Cross-section DUN-DUN' demonstrates that sandstones are distributed irregularly throughout the Dunvegan, and that regional correlation of individual allomembers is difficult. Detailed net sandstone mapping, by allomember, would be necessary to make sense of potential tight gas reservoir distribution.

### Hydrocarbon Occurrences

Numerous pools produce oil and some gas in Alberta, immediately east of the B.C. border. Most of these produce from thin, conventional reservoir sandstones in the Doe Creek; a few of these have been discovered in B.C. (e.g., well d-93-A/93-P-8, Cross-section DUN-DUN').

Map 2 shows that drillstem tests have flowed low-rate gas from Dunvegan tight sands in several wells in B.C. To date, none have been completed for economic flow rates. As for the Cardium, no reservoir "sweet spots" have been identified.

## **SIKANNI / GOODRICH SANDSTONES (Uppermost Albian – Lower Cretaceous)**

### Stratigraphy and Distribution

Sikanni/Goodrich strata comprise up to seven coarsening-upward deltaic to shoreface successions in northeastern B.C. They overlie marine shales of the Buckingham and Hasler formations, and are capped by Cruiser and Sully shales. The Goodrich is recognized in the Peace and Pine River areas, while the Sikanni has been mapped in the vicinity of Sikanni Chief River and northward. Stott (1982) mapped the regional distribution of these units; more recent work by Schroder-Adams and students (Jowett and Schroder-Adams, 2002; Pedersen et al., 2000, 2001; Schroder-Adams and Pedersen, 2002; Schroder-Adams, et al., 2000) has provided additional regional stratigraphic context.

Map 4 shows very extensive Sikanni and Goodrich outcrop along the eastern margin of the northeastern B.C. Foothills, and some of the key outcrop sections described in the literature. Figure 3 illustrates lateral continuity of the Sikanni and Goodrich for more than 400 km along strike, while Fig. 2 shows their eastward stratigraphic pinchout. Gross thicknesses up to 240 metres have been recorded, although most are substantially less (Stott, 1982).

In the subsurface, the Sikanni/Goodrich occupies a long, narrow trend, bounded to the east by a poorly-defined sandstone progradational limit (Map 4). Drill depths are 1500 metres or less in most areas, and much of the prospective fairway is very lightly explored.

### Reservoir Description

In outcrop, Sikanni/Goodrich sandstones are predominantly fine-grained, somewhat argillaceous litharenites, petrographically similar to fine-grained *Cardium* sandstones. Jowett and Schroder-Adams (2002) described isolated conglomerates in Liard Basin outcrops.

Very few cores have been cut; Core log 2 illustrates the upper part of the Sikanni section at Bougie (Pedersen and Schroder-Adams assign this section to a slightly older unit – the Bougie sandstone member). Sandstones are very fine-grained and heterolithic, with a significant proportion of wavy shale beds (Photo 2-4). A diverse but only moderately-abundant ichnofauna, and the presence of isolated soft-sediment deformation (Photo 2-5), points to delta front to lower/middle shoreface environments of deposition.

Reservoir quality is poor in the Bougie a-85-A well; core analysis porosities range up to 13%, but permeabilities are generally less than 0.1 md. Thin shale beds reduce vertical permeabilities to even lower values. Thin sections show that reservoir quality is degraded by fine grain size and abundant matrix clays

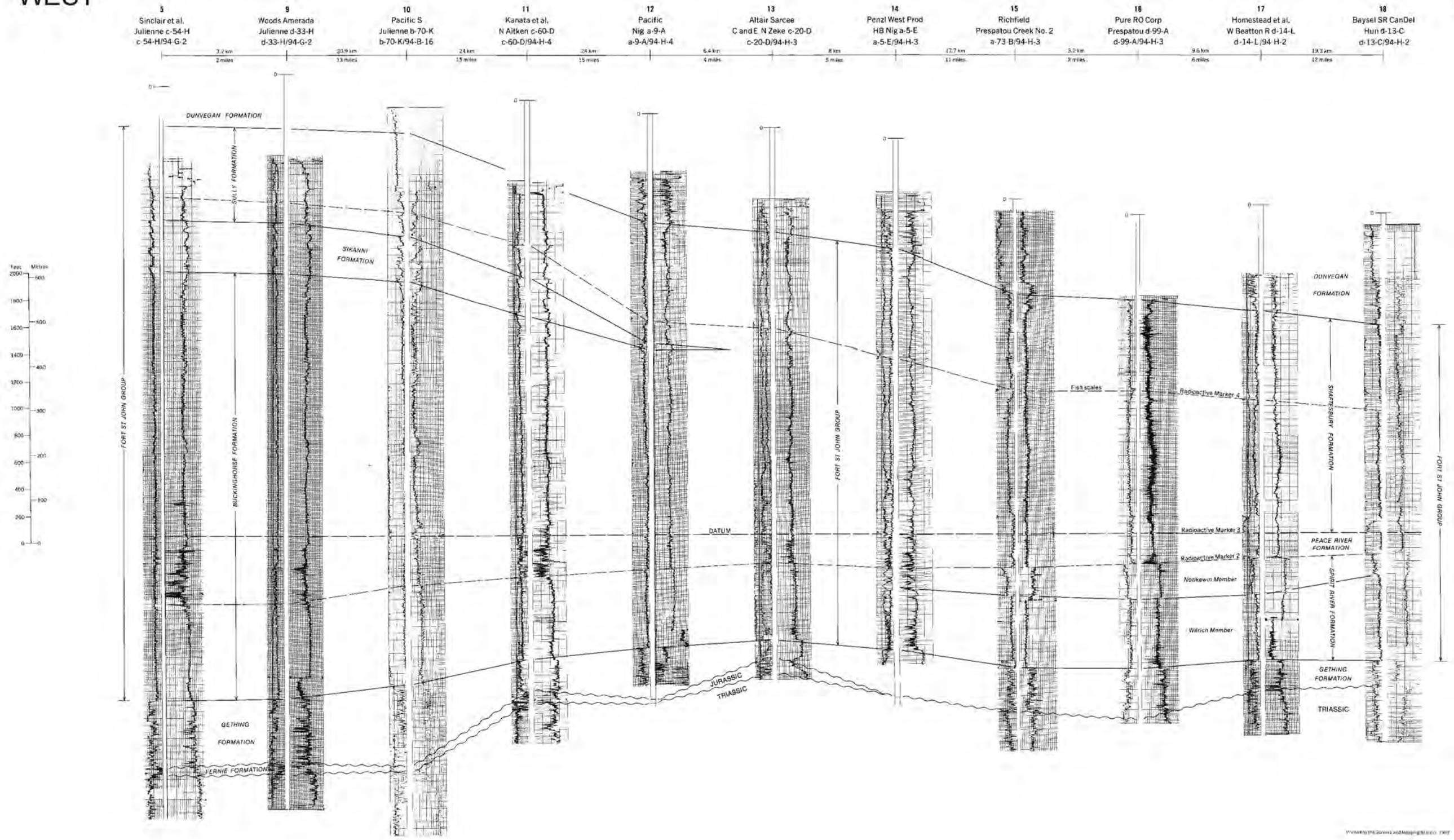


Fig. 2. Cross-section SIK1-SIK1', showing west-to-east pinchout of Sikkani Formations sandstones within Fort St. John shales (from Stott, 1982).

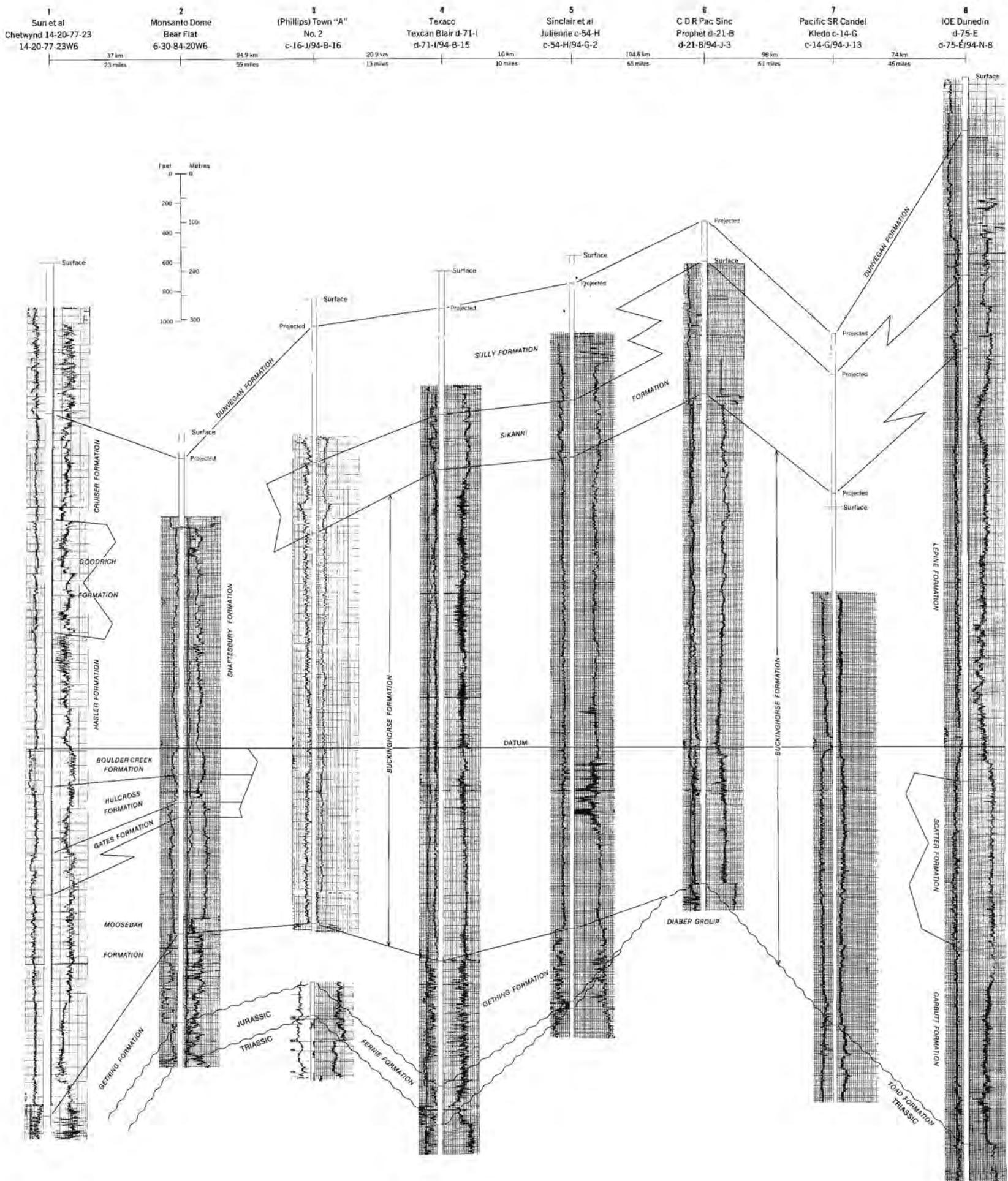


Fig. 3. Cross-section SIK2-SIK2', showing continuity of Sikanni and Goodrich sandstones along strike (SSE-NNW) (from Stott, 1982).

(Photo 3-2). Heterolithic Sikanni/Goodrich reservoirs would benefit less from fracturing than more brittle, sand-rich units.

No attempt was made to map net sandstone in the Sikanni/Goodrich. Much more core and production/test data are required to correlate log parameters with reservoir quality.

### Hydrocarbon Occurrences

Sikanni/Goodrich sandstones are not productive, and only the Bougie a-85-A well has flowed gas upon completion (Map 4). Scattered drillstem tests have recovered mud only, so we cannot interpret distribution of potential Deep Basin or regional aquifer fairways.

## **SCATTER FORMATION** (Albian – Lower Cretaceous)

### Stratigraphy and Distribution

The Scatter Formation was deposited in shallow marine shelf to shoreline settings. Two sandstone members, the Tussock and Bulwell, are recognized in outcrop, but generally are not distinguished in the subsurface. Marine shales of the Garbutt Formation below and the Lepine Formation above encase the Scatter (Fig. 4). Stott (1982) mapped the Scatter in outcrop, and Leckie and Potocki (1998) provided a detailed sedimentological and petrographic analysis in outcrop and the subsurface of the Liard Basin.

Scatter sandstones occur in the Liard Basin and northward into the southern Northwest Territories (Fig. 4, Map 5). Present-day burial depths range up to about 1700 metres, increasing to the southwest. From isopach and net sandstone distributions, Leckie and Potocki (1998) interpreted major depocentres to the west and southwest of the Liard Basin. Regional cross-sections (Fig. 5-7) illustrate the Scatter in the subsurface; although it clearly thins eastward, there is no well-defined eastern sandstone limit.

### Reservoir Description

Scatter sandstones are silty to very fine-grained, moderately- to well-sorted, matrix-rich, moderately to poorly porous, glauconitic and lithic. Much of the clay matrix is pseudomatrix, produced by ductile deformation of labile framework grains. Compaction has thus greatly reduced porosity and permeability; in addition, locally abundant calcite cement has further reduced reservoir quality.

There is only one cored Scatter section in B.C., at IOE Dunedin a-75-E/94-N-8. Core analysis porosities range from 8 to 12%, with maximum permeabilities up to 0.2 md. Vertical permeability measurements are <0.01 md, indicating lack of

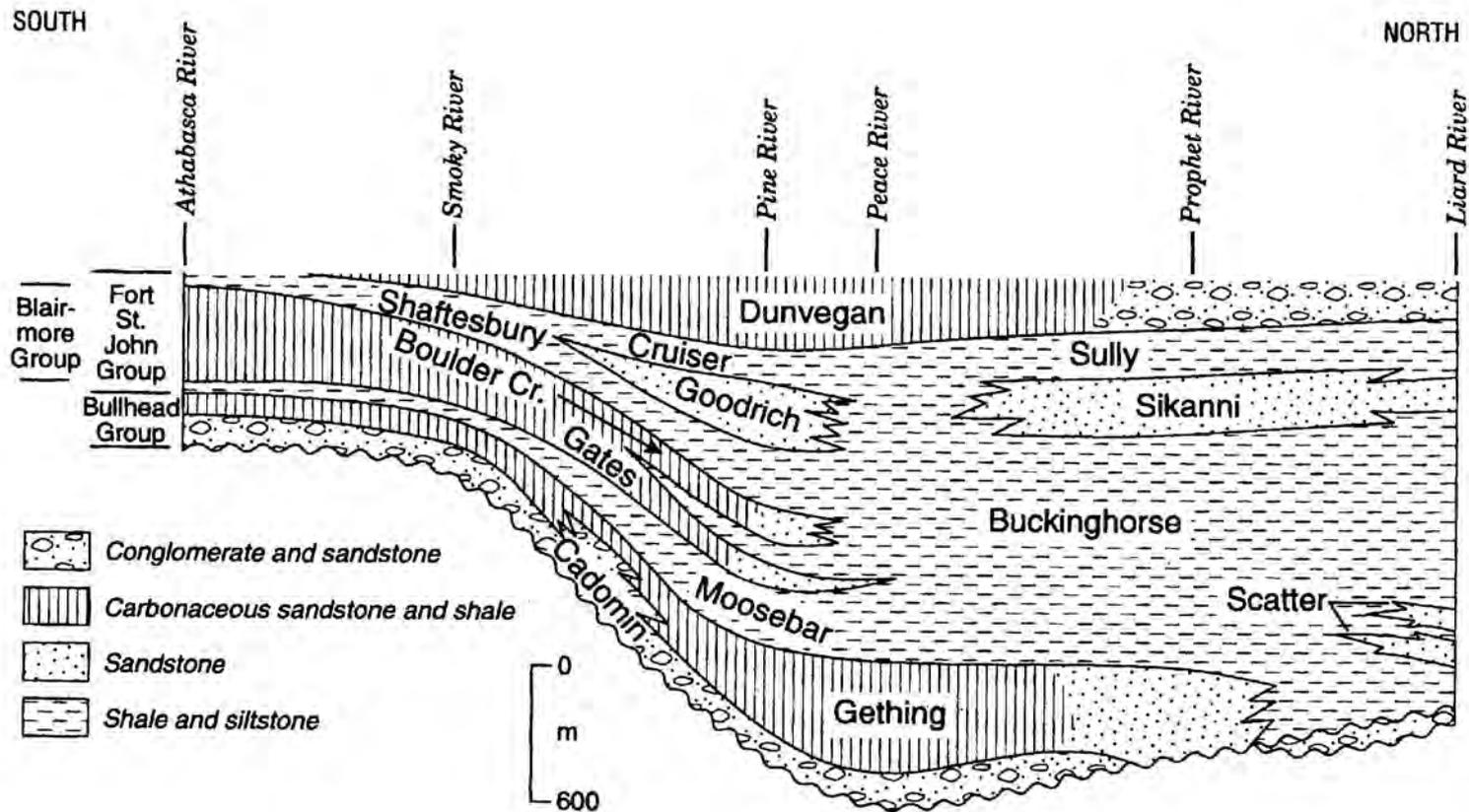


Fig. 4. Schematic stratigraphic cross-section, Fort St. John Group, northeastern B.C. Note limited geographic distribution of Scatter Formation (from Leckie and Potocki, 1998).

A  
WEST

A'  
EAST

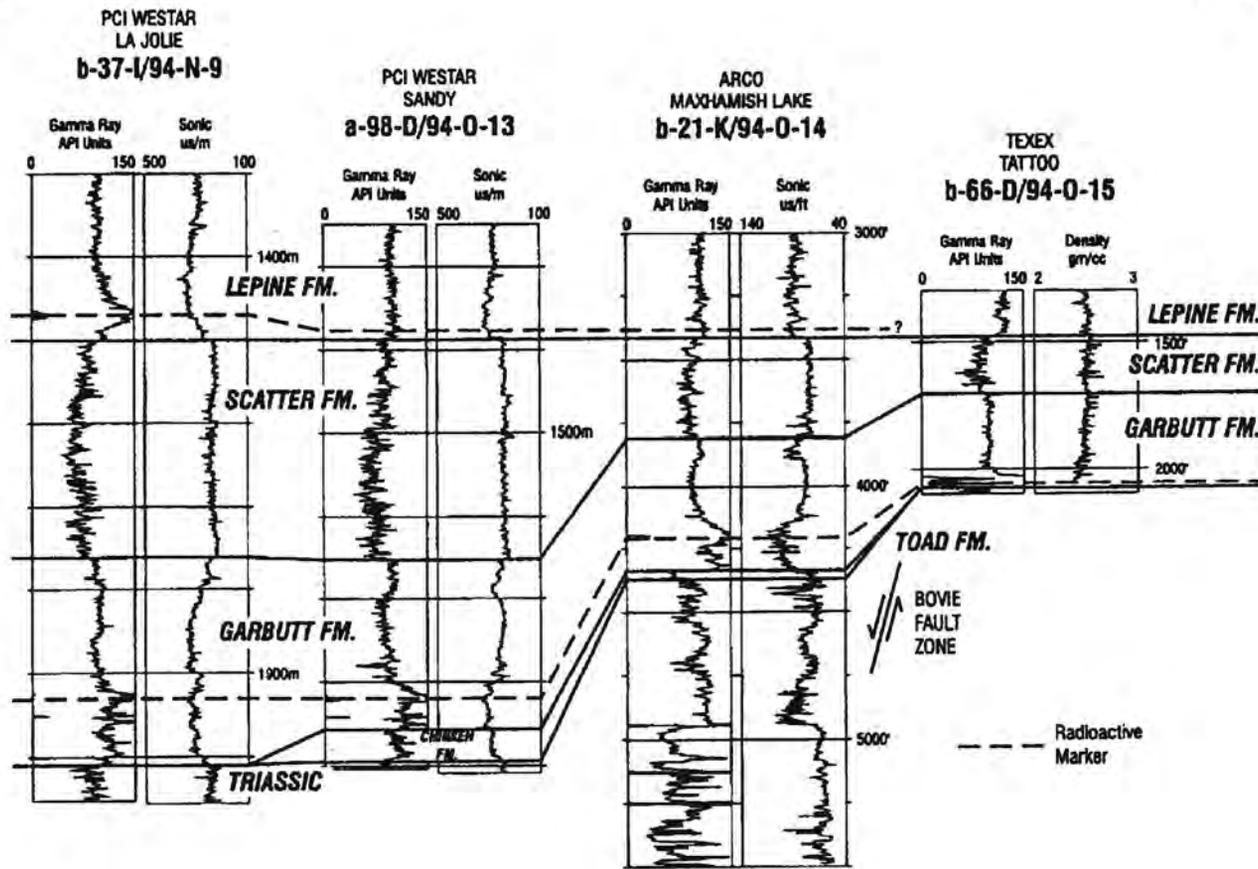


Fig. 5. Cross-section A-A', highlighting distribution of Scatter Formation in the Liard Basin (from Leckie and Potocki, 1998).

B  
WEST

B'  
EAST

PETROY et al  
DUNEDIN  
a-39-B/94-N-8

HB BCRIC  
LIARD  
a-15-G/94-O-5

AQUITAINE et al  
DONNAMARIE  
a-93-C/94-O-6

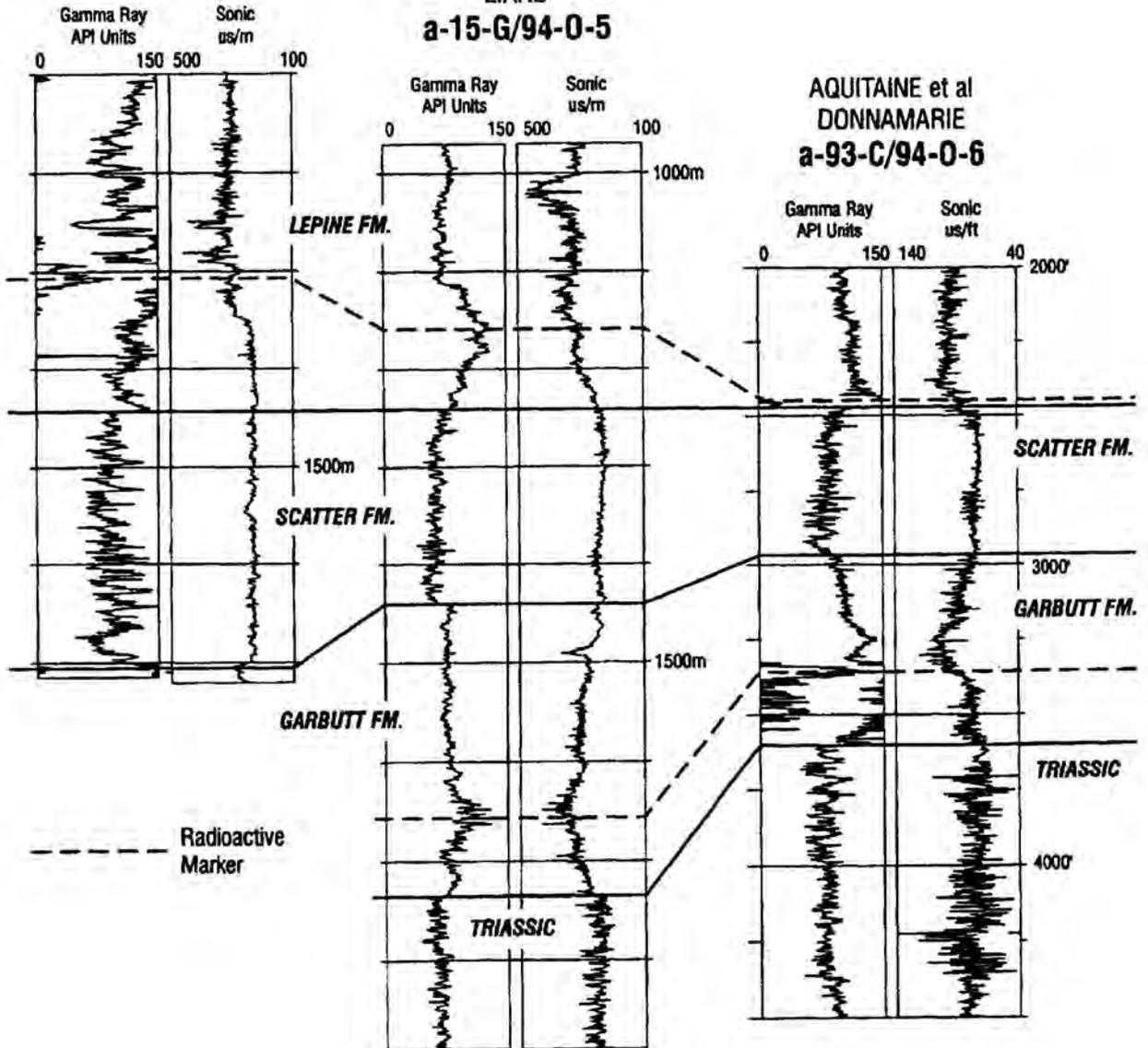


Fig.6. Cross-section B-B', highlighting distribution of Scatter Formation in the Liard Basin (from Leckie and Potocki, 1998).

next page

C  
NORTH

C'  
SOUTH

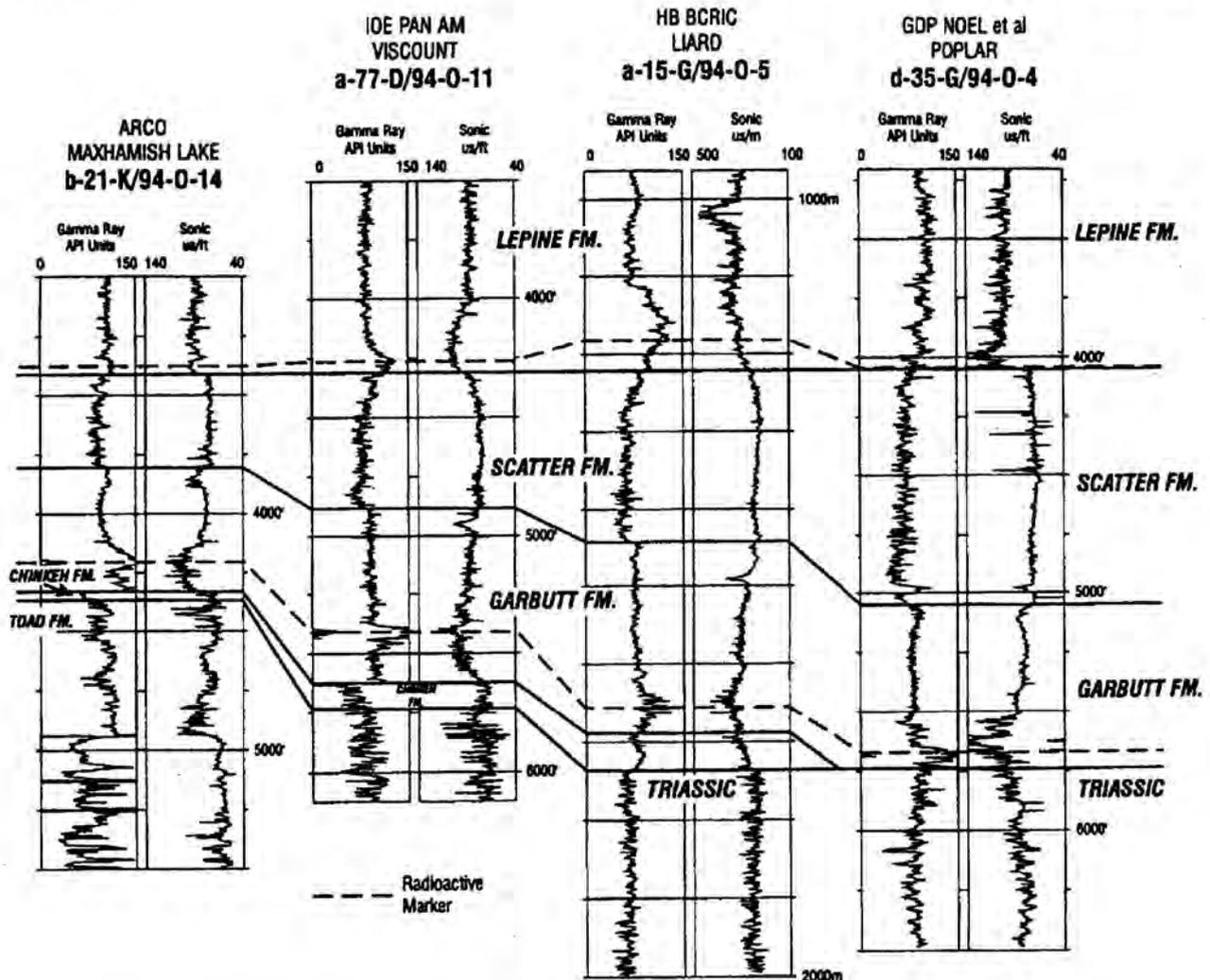


Fig. 7. Cross-section C-C', highlighting distribution of Scatter Formation in the Liard Basin (from Leckie and Potocki, 1998).

vertical reservoir continuity, probably due to interbedded mudstones. Leckie and Potocki (1998) noted porosity values of 0 to 11% from outcrop samples. They noted no potential for coarser rocks with better reservoir quality.

Leckie and Potocki (1998) mapped net sandstone thickness from outcrop and subsurface (Map 5), but did not specify their mapping parameters. Comparing logs with isopach values, it appears gamma log cut-off values of 75-90 API units have been used. These are probably reasonable, given the relatively high percentage of lithic grains and feldspars in the Scatter. Net sandstone thickness of greater than 100 metres over the western part of the Liard Basin indicate considerable tight gas potential.

### Hydrocarbon Occurrences

Scatter sandstones have produced no hydrocarbons to date. Drillstem tests have yielded only mud, while the few completions attempted have failed to produce gas flows (Map 5). One well tested some water, but this may be a mud filtrate recovery.

All Scatter penetrations to date have been in wells targeted for deeper objectives. There has thus been no systematic effort to evaluate the Scatter reservoir with carefully-designed drilling and completion programs.

## **CADOTTE MEMBER (Albian – Lower Cretaceous)**

### Stratigraphy and Distribution

The Cadotte is the uppermost of several Lower Cretaceous shoreface units stacked along the southern margin of the Peace River Embayment. In B.C., it progrades northward through 93I and 93P, reaching a northerly limit in Townships 78-80 (Map 6; Cross-section CDT-CDT'). The Cadotte interfingers with underlying Harmon marine shales, and grades up into continental to bay-fill strata of the lower Paddy Member. Burial depths range from 800 metres in the northeast to more than 3000 metres in southern 93I. Outcrop equivalents (Boulder Creek Formation) have been mapped and described by Stott (1982) and Gibson (1992b), while several authors have described the Cadotte in the subsurface (e.g., Smith et al., 1984; Hayes, 1988; Leckie et al., 1990).

Cadotte shoreface sandstones form classical coarsening-upward successions. At the base, hummocky cross-stratified sandstone interfingers with Harmon shales, and grades up to massive to swaley cross-stratified very fine-grained middle shoreface sandstone (Photo 2-6). Coarser-grained upper shoreface sandstone and conglomerate lie abruptly on the lower shoreface (Core log 3, 4; Photo 2-7). Capping foreshore sandstones are generally somewhat finer, and are more or less conformably overlain by coastal plain strata of the Paddy

Member (Photo 2-8). Channelized sections have been noted in outcrop and subsurface (Photo 1-3), and Hayes (1988) mapped a southwest-northeast paleovalley system incising the top of the Cadotte in the Noel area (Map 6).

### Reservoir Description

Cadotte conglomerates and coarse-grained sandstones are excellent reservoirs where sufficiently well-sorted. At Canhunter Noel b-24-A (Core log 3), upper shoreface and foreshore strata exhibit porosities of 6-12%, and permeabilities ranging up to hundreds of millidarcies (Photo 2-9, 2-10). Petrographically, these rocks are chert litharenites, with well-developed intergranular porosity (Photo 3-3).

Volumetrically, however, the Cadotte is dominated by much poorer-quality reservoirs. Very fine-grained middle shoreface sandstones exhibit porosities of 5-7%, and permeabilities on the order of 0.1 md or less. In locations where upper shoreface and foreshore facies lacked a consistent pebble supply during deposition, reservoir quality is heterogeneous and generally poor, with only isolated beds exceeding 7% porosity and 1 md permeability (Core log 4; Photo 2-11, 2-12). Photo 3-4 highlights the degradation of porosity by finer grains, quartz overgrowths, and kaolinite cement.

Net clean sandstone thicknesses (based on a 75% clean gamma ray cut-off) range from less than 5 to more than 50 metres, with most areas in the 15-25 metre range (Map 6). Sandstones occur in massive sections, with little interbedded mudstone.

### Hydrocarbon Occurrences

The Cadotte is an established gas producer in the B.C. Deep Basin (Map 6). Conglomeratic sweet spots host pools ranging up to 1768 e<sup>6</sup>m<sup>3</sup> (62 BCF) in size, and initial well deliverabilities range from <25 to 750 e<sup>3</sup>m<sup>3</sup>/d. There is a clearly-defined, subnormally-pressured Deep Basin regime, with an updip regional aquifer system containing isolated gas pools in stratigraphic traps.

Outside of the major pools in the Deep Basin, numerous tests demonstrate the presence of low-permeability, gas-saturated reservoirs, with isolated “sweet spots” featuring conventional reservoir quality. Very few Cadotte sections have been tested in the southwestern Foothills area, but a gaswell at c-63-G/93-I-15 flags the possibility that structural deformation and fracturing may enhance reservoir quality.

In the updip regional aquifer system, controls on gas trapping are not entirely clear. Production in established pools is from coarse-grained strata with conventional reservoir quality. If tight gas potential exists, it will likely be in limited areas, with considerable risk of water.

## **SPIRIT RIVER FORMATION (Albian – Lower Cretaceous)**

### Stratigraphy and Distribution

The Spirit River Formation in the southern Deep Basin comprises six major stacked shoreface units, much like the Cadotte Member, situated along the southern margin of the Peace River Embayment. As a package, they prograde northward through 93I and 93P, reaching a northerly limit in Townships 76-78 (Map 7; Cross-section SR-SR'). From the top down, individual shoreface successions are termed Notikewin, Falher A, B, C, D, E, and F (Photo 1-4). Spirit River sandstones grade upward from Wilrich marine shales below, and are truncated sharply by Harmon shales above. Burial depths range from 1000 to more than 3000 metres in the southern Deep Basin. Spirit River stratigraphy has been documented extensively in outcrop (e.g. Stott, 1982; Walker and Leckie, 1982) and the subsurface (e.g. Smith et al., 1984; Hayes et al., 1994; Cant, 1995).

Falher and Notikewin successions are very similar to the Cadotte, consisting of coarsening-upward middle to upper shoreface sandstones and conglomerates, capped by coaly coastal plain facies (Core log 5, 6). Where the Falher/Notikewin successions are optimally developed, each is clearly distinguishable on well logs (e.g. well d-95-A/93-P-1, Cross-section SR-SR').

To the north, Spirit River shorefaces grade to a distal coarsening-upward succession, within which individual subunits have not been correlated regionally (Cross-section SR-SR'). Anomalously clean sands host isolated gas reservoirs, as at Pickell (e.g., well c-61-J/94-H-3, Cross-section SR-SR'). These sands have not been documented in detail, but Core log 7 indicates a deltaic to shoreface succession. Their stratigraphic position suggests deposition during a relative sea-level fall, following deposition of the southerly Spirit River succession.

### Reservoir Description

Well-sorted conglomerates and coarse-grained sandstones in the upper shoreface to foreshore are reservoir “sweet spots”, with quality comparable to similar facies in the Cadotte. Less-sorted, finer-grained rocks are poorer reservoirs – compare the upper shoreface reservoir quality in the Falher A at b-28-G/93-P-1 (Core log 6) (Photo 2-14) with the Falher B in b-2-H/93-P-1 (Core log 5) (Photo 2-13). Spirit River shoreface strata are dominated volumetrically by poorer-quality reservoirs, including extensive tight middle shoreface sandstones (Photo 2-15).

Spirit River sandstones are chert litharenites, with chert increasingly dominant in coarser-grained rocks (Appendix 4; Photo 3-5). Compaction and quartz and carbonate cements severely degrade reservoir quality in finer facies (Photo 3-6).

Net clean sandstone thicknesses (based on a 75% clean gamma ray cut-off) range up to 100 metres (Map 7), representing an extremely thick and widespread tight gas resource.

The northerly lowstand delta/shoreface at Pickell appears to have conventional reservoir quality despite its fine grain size (Core log 7). We speculate that this may be due to relatively shallow burial and limited compaction.

### Hydrocarbon Occurrences

Conglomeratic sweet spots in Spirit River shorefaces are the predominant reservoirs in the Deep Basin (Map 7). Initial raw gas reserves exceed 9600 e<sup>6</sup>m<sup>3</sup> (340 BCF) in the Noel-Kelly field areas, which lie to the west of much more extensive gas pools in Alberta. There is a clearly-defined, subnormally-pressured Deep Basin regime, with an updip aquifer, for each of the Falher and Notikewin shoreface successions.

Outside of the major pools, numerous tests demonstrate the presence of low-permeability, gas-saturated reservoirs, with isolated sweet spots featuring conventional reservoir quality. Fracturing associated with structural deformation may play a role in reservoir development at Grizzly North (Map 7).

Gas production from northerly lowstand shoreface reservoirs appears to originate in structural and/or stratigraphic traps in conventional reservoir sandstones, and will not be analyzed further in this report.

## **BLUESKY FORMATION (Albian – Lower Cretaceous)**

### Stratigraphy and Distribution

Bluesky tight gas production and potential occurs in two settings in northeastern B.C. – within the Chamberlain Delta and associated basal Bluesky units in the southern Deep Basin, and within the fill of the Buick-Laprise Valley complex on the northwestern margin of the Peace River Block (Map 8).

The Chamberlain Delta is a northerly-prograding wedge of clastics, separated from the underlying Gething Formation by the Bullmoose Member, a transgressive marine shale, and capped by Wilrich marine shales (Cross-section BLU-BLU'). Beneath the Bullmoose shale, relatively thin channel and shoreface successions lie sharply on Gething continental facies, and are termed the "basal Bluesky" in field nomenclature. Burial depths range from 1500 to more than 3000

metres. The Chamberlain Delta is well-documented in outcrop (e.g., Legun, 1984a, 1985; Gibson, 1992a), but has received little attention in the subsurface. O'Connell (1998) discussed equivalent strata at Sexsmith, 50 km east of the Alberta border.

To the north, Bluesky strata are relatively thin and discontinuous, although production occurs locally from transgressive shoreface strata with conventional reservoir quality. In the Buick Creek – Laprise area, however, Petrel Robertson (1997) mapped an extensive valley system incising the Gething, filled with estuarine/fluviol facies (Map 8; Cross-section BLU-BLU'). The valley can be traced continuously through northern 94B and into 94-G-1, and Petrel Robertson mapped it as far northeast as 94-H-6, based upon discontinuous remnants of the valley fill. Alway and Pemberton (1997) described one such remnant at Aitken Creek. Burial depths are generally less than 1500 metres, and many sections near the western outcrop limit are shallower than 1000 metres.

Chamberlain Delta strata have not been cored in the B.C. Deep Basin. At Sexsmith, O'Connell (1998) logged medium-grained fluvial sandstones over very fine-grained delta front to middle shoreface sands. In outcrop, Gibson (1992a) noted abundant fine- to coarse-grained sandstones and conglomerates, with subsidiary finer clastics and coal. Well logs suggest an overall coarsening- and sandier-upward succession composed dominantly of sandstone, grading to channelized/continental strata to the south (Cross-section BLU-BLU').

The basal Bluesky appears to consist of two or more depositional sequences, which have not been mapped or interpreted regionally. Core log 8 shows a shoreface to delta front succession consisting of fine-grained sandstones, capped by a thin coal (Photo 2-16). At b-18-E (Core log 9), a fining-upward channel unit caps the succession (Photo 2-17). Sample cuttings show that most productive sections, as at d-55-D/93-P-8 (Cross-section BLU-BLU'), are conglomeratic.

Valley-fill facies in the Buick-Laprise valley system consist primarily of fine- to medium-grained sandstones. Some sections are massive, while others exhibit a limited ichnofauna suggestive of marginal marine to estuarine environments (Core log 10; Photo 2-18). Pebbly sandstones and conglomerates, deposited in more fluvial-influenced settings, occur throughout the section. Well-sorted conglomerates host many of the conventional pools in the updip portion of the valley complex (Photo 2-19).

### Reservoir Description

Based upon sample cutting descriptions and test data, Chamberlain Delta sandstones appear to be poor reservoir rocks, likely as the result of compaction and cementation. The basal Bluesky delta/shoreface and channel successions cored are similarly poor reservoirs, with core analysis porosities rarely exceeding

5%, and permeabilities of 0.1 md or less (a permeability spike at the top of the d-73-D section is likely related to fracturing and/or fluid movement along root traces). Thin sections show that compaction and quartz cementation have significantly reduced intergranular porosity in such fine-grained rocks; at b-18-E (Core log 9), carbonate cement virtually eliminates porosity. Conglomeratic sweet spots in the basal Bluesky possess reservoir characteristics very much like Cadotte and Spirit River shorefaces, but these represent only a small fraction of the Deep Basin Bluesky section.

Net sandstone values for the Chamberlain Delta are interpreted using a less rigorous cut-off than for Cadotte and Spirit River sands, to allow for somewhat more lithic/feldspathic lithologies and more interbedded mudstones. Even so, net sand thicknesses exceed 20 metres only in the west-central area (Map 8). Basal Bluesky sands were not included because of their irregular and limited distribution.

Bluesky valley-fill sections in the Buick-Laprise valley system exhibit very low porosities and permeabilities, as the result of compaction and cementation (core analysis, Core log 10; Photo 3-8). Secondary solution porosity is commonly developed in updip pools, and may occur locally downdip. Reservoir quality may also be enhanced by structurally-generated fracturing to the west. Bluesky valley fill net sands (calculated on a 75% clean gamma ray cut-off) range up to 40 metres thick (Map 8).

### Hydrocarbon Occurrences

Basal Bluesky sandstones and conglomerates produce gas in the southern Deep Basin, but the sweet spots appear to have very limited lateral extent; only d-55-D/93-P-8 has produced in excess of 100 e<sup>6</sup>m<sup>3</sup>. Most of the tests mapped were run on the basal Bluesky, with very few tests in the Chamberlain Delta unit. There are no obvious occurrences of formation water throughout the southern Deep Basin, so we assume that a gas-saturated Deep Basin regime is present.

There are several isolated producers in the Buick-Laprise valley fill, with two multi-well pools at Altares (94-B-8, Map 8). Most other sections have tested tight, while three well tested water. Further work needs to be done to determine whether these are formation waters, and whether they originate within a regional aquifer, or from local fracture systems.

## **CADOMIN – GETHING FORMATIONS** (Aptian and older – Lower Cretaceous)

### Stratigraphy and Distribution

Cadomin and Gething tight gas potential in B.C. occurs in two areas. In the southern Deep Basin, widespread Cadomin conglomerates are the primary target, with only isolated channels in the overlying Gething section. To the north, the Cadomin is absent, but lower Gething sandstones fill the Buick-Laprise valley (Map 9).

*Southern Deep Basin* – The Cadomin is a very widespread alluvial fan deposit, and lies on a profound regional unconformity. It is recognized as far south as the U.S. border, and reaches a northern limit near the northwestern corner of the Peace River Block (Map 9). It has been documented extensively in outcrop (e.g., McLean, 1977; Stott, 1973; Legun, 1984b) and in the subsurface (e.g., Gies, 1984; Smith et al., 1984; Varley, 1984). Gething potential in the southern Deep Basin is restricted to isolated channel sandstones (Cross-section CDM-CDM'). Burial depths range from 1500 to more than 3200 metres.

Cadomin strata consist of poorly-sorted siliceous conglomerates and sandstones, lacking pronounced vertical trends or bedding features (Core log 12; Photo 2-20). Several depocentres have been identified in outcrop, where thicknesses can exceed 100 metres and clast sizes reach tens of centimetres (McLean, 1977) (Map 9 – Mount Belcourt and Peace River fans; Photo 1-6). To the east in the subsurface, the Cadomin becomes finer-grained and better-sorted with fluvial reworking in the Spirit River Valley system (Gies, 1984).

*Buick-Laprise Valley* – The Gething Formation is a thick, mud-rich continental succession in the southern Deep Basin (Gibson, 1992a; Smith et al., 1984) (Photo 1-7, 1-8). North of the Cadomin subcrop edge, it lies on the pre-Cretaceous unconformity, which exhibits considerable relief. Petrel Robertson (1997) and Hayes (1999) traced a major valley system in the Buick-Laprise area, and mapped a thick Gething fill (Cross-section CDM-CDM'). The Gething valley underlies, but is distinctly older than, the Bluesky Buick-Laprise valley. Lower Gething sandstones within the valley offer considerable reservoir potential, whereas the upper Gething contains only isolated channel reservoirs. Burial depths rarely exceed 1500 metres.

Lower Gething valley fill strata consist of stacked, fining-upward fluvial sandstones, capped by a coaly floodplain section (well b-59-C/94-G-1, Cross-section CDM-CDM'). Sandstones are generally fine- to medium-grained, with coarser grains and floating pebbles in places. There are very few cores, but at b-17-K/94-G-1 (Core log 11), the section exhibits poorly-developed low-angle cross-bedding and moderate to poor sorting; stylolites indicate that considerable compaction has taken place.

## Reservoir Description

Cadomin sandstones and conglomerates are poorly-sorted chert litharenites. Sand grains fill most interpebble pore spaces, while quartz overgrowths and kaolinite further degrade reservoir quality (Photo 3-9). Core analysis data (Core log 12) show porosities of 5% or less, and low permeabilities. Permeability spikes above 1 md are likely the product of fractures. Varley (1984) noted better reservoir quality in the Cadomin near the updip edge of the Deep Basin. Cadomin sandstones are highly siliceous and very brittle, and thus are likely to be extensively fractured where structural deformation has taken place.

Net clean sandstone thicknesses (based on a 75% clean gamma ray cut-off) range up to 90 metres (Map 9). There are insufficient control points in more westerly sections to accurately reflect the rapid thickening of the section toward the Mount Belcourt and Peace River depocentres.

Lower Gething sandstones at Buick-Laprise exhibit somewhat better reservoir quality, but can still be considered as tight sands. Core analysis at b-17-K (Core log 11) show porosities of 5-9%, and permeabilities of less than 0.5 md, ranging up to a few millidarcies in isolated beds. Poorer reservoir quality can be expected with increased compaction further to the west, but structural deformation may also generate fractured reservoirs.

Net clean sandstone isopachs in the Buick-Laprise Valley demonstrate the excellent lateral continuity of lower Gething reservoirs. Preliminary work by Petrel Robertson indicates that additional valley trends may exist to the south, in the northern part of the Peace River block.

## Hydrocarbon Occurrences

*Southern Deep Basin* – The Cadomin features a well-defined gas-saturated Deep Basin regime (Gies, 1984; Map 9). Unlike the overlying marine Cretaceous units, however, it lacks well-sorted reservoir “sweet spots” in British Columbia. Numerous drillstem tests and completions confirm the widespread presence of gas in low-permeability reservoirs. Production at Kelly Lake is at least in part from better-sorted but isolated Gething channel sands.

*Buick-Laprise Valley* - Relatively few lower Gething sections have been tested, as most wells are targeted to deeper horizons, and well logs indicate subeconomic reservoir quality. Gas is clearly widespread, but it is unclear whether a gas-saturated Deep Basin regime exists. Further to the east (94-H-6 and eastward), more conventional reservoir quality occurs in the lower Gething, which hosts several oil and gas pools.

## **MINNES GROUP (NIKANASSIN – BUICK CREEK)** (Upper Jurassic – Lower Cretaceous)

### Stratigraphy and Distribution

Minnes Group strata are known primarily from outcrop work (summarized in Stott, 1998), as they are not commonly regarded as prospective reservoirs in the subsurface. Stott's regional mapping outlines a massive depositional complex, extending from coastal plain to shoreface strata of the Kootenay Group in southern Alberta and B.C., to a northerly depositional limit in the Minnes Group, northwest of the Peace River Block in northeastern B.C.

In the southern Deep Basin of west-central Alberta and adjacent B.C., Minnes strata can be mapped a considerable distance eastward from outcrop, where they are termed the Nikanassin Formation. Nikanassin strata grade upward from Fernie marine shales, and are unconformably overlain by the Cadomin. Total thicknesses can exceed 800 metres, and burial depths range up to 3500-4000 metres. Well logs show interbedded sandstones and shales with thin coal beds, lacking regionally correlative surfaces or clearly-defined depositional trends (Cross-section NIK-NIK'). At a-23-H/93-P-8, fine- to medium-grained sandstones appear to have been deposited in channel environments (Core log 13; Photo 2-21, 2-22).

Northward, Nikanassin strata grade into medium- to coarse-grained quartzarenites in the Rigel-Buick Creek area (Cross-section NIK-NIK'). Petrel Robertson (1997) mapped these strata as the Buick Creek sandstone, and interpreted them as the remnants of an easterly-derived delta system, deposited on the eastern flank of the foredeep (Map 10). Core log 14 illustrates a typical Buick Creek section; however, much more coal occurs locally elsewhere (Photo 2-23).

### Reservoir Description

Nikanassin sandstones in the a-23-H well are poorly- to moderately-sorted, fine- to coarse-grained litharenites. They have been highly compacted, and extensively cemented by silica. Reservoir quality ranges from very poor (Photo 3-10) to slightly less poor (Photo 3-11). These brittle, siliceous rocks are prone to fracturing and possible reservoir enhancement. Map 10 shows that net clean sand thickness exceed 100 metres over large areas. Most sandstones occur in bodies 25 metres or more thick, separated by thick shaly intervals (Cross-section NIK-NIK').

Buick Creek quartzarenites are excellent conventional reservoirs at Buick Creek, Fireweed, and Rigel (Map 10; well 6-21-88-18W6, Cross-section NIK-NIK'; Photo 3-12). To the west, however, they degrade rapidly through extensive quartz cementation (Photo 3-13). Buick Creek production in this area is confined to

structural culminations, where fracture enhancement has occurred (e.g., well a-24-B/94-B-16, Cross-section NIK-NIK'). Net clean sand thicknesses range up to 40 metres in the east, but thicken westward into the foredeep (Map 10).

### Hydrocarbon Occurrence

The Nikanassin does not produce as a conventional reservoir, except in isolated locations. At b-48-H/93-P-1, an anomalous development of secondary porosity in Nikanassin sands yielded a high-quality gaswell, which drained a very small area. Tests elsewhere indicate very poor reservoir quality. A gas-saturated Deep Basin regime probably exists, but cannot be identified with confidence.

Buick Creek sandstones host large conventional gas fields in the east, which have small associated aquifers. To the west, most structural culminations have tested gas. It is unclear whether regional aquifers are present in this area, but water must be regarded as a risk.

## **PARDONET / BALDONNEL (Upper Triassic)**

### Stratigraphy and Distribution

Pardonet / Baldonnel strata are widespread shallow marine to shelfal carbonates, which have been documented comprehensively by Davies (1997). The Baldonnel can be mapped continuously from the southern Deep Basin to a northern subcrop edge in 94G and 94H (Map 11). It lies more or less conformably on the Charlie Lake Formation, while the Pardonet (and Baldonnel east of the Pardonet subcrop edge) is unconformably overlain by Jurassic marine shales.

Moslow and Davies (1993) documented four Pardonet/Baldonnel play trends in northeastern B.C.:

- Fracture-dominant Foothills structural play (Bullmoose/Sukunka)
- Foothills structural – Cypress area
- Baldonnel linear fold play
- Baldonnel combination stratigraphic-structural play (Plains area)

These play fairways are outlined on Map 11. The first two are predominantly tight gas plays, whereas the linear fold play depends upon both conventional reservoirs and fracture enhancement. Pools in the Plains play type are generally conventional reservoirs.

## Reservoir Characteristics (Tight Gas Plays)

*Fracture-dominant Foothills Structural Play* – Fault-propagation folds involving Upper Triassic carbonates, formed during Laramide thrusting, are the principal traps (Fig. 8). Reservoir rocks have low matrix porosities (less than 4%) and permeabilities less than 0.1 md, and are buried to depths of 2400 to 3000 metres. Fracturing is the key element to productivity, producing flow rates up to 2400 e<sup>3</sup>m<sup>3</sup>/d (Morrison and Cooper, 1992; Moslow and Davies, 1993). Barss and Montandon (1981) originally documented this play trend.

*Foothills Structural Play, Cypress Area* - Although similar to the Bullmoose/Sukunka play, pools in this play trend are shallower (675 to 1500 metres), in less complex structures, and produce from both matrix porosity and fractures. Optimal matrix porosity and fracturing occur where the Baldonnel is dolomitized; there is little production from pelagic limestones in the Pardonet Formation (Moslow and Davies, 1993).

*Baldonnel Linear Fold Play* – Traps occur in NNE-SSW trending long, linear, low-relief folds generated by Laramide compression. Conventional matrix porosity in dolomitized Baldonnel carbonates is the dominant reservoir type, but fractures enhance permeability. This play lies on the eastern margin of true tight gas plays in the Pardonet/Baldonnel. Several other tight reservoirs – Gething, Cadomin, Buick Creek, and Halfway – occur on this play trend, resulting in many multiple completions and twinned wells.

Average porosity figures for Pardonet/Baldonnel pools are plotted on Map 11, highlighting the relatively low, unconventional porosity in the western structural plays.

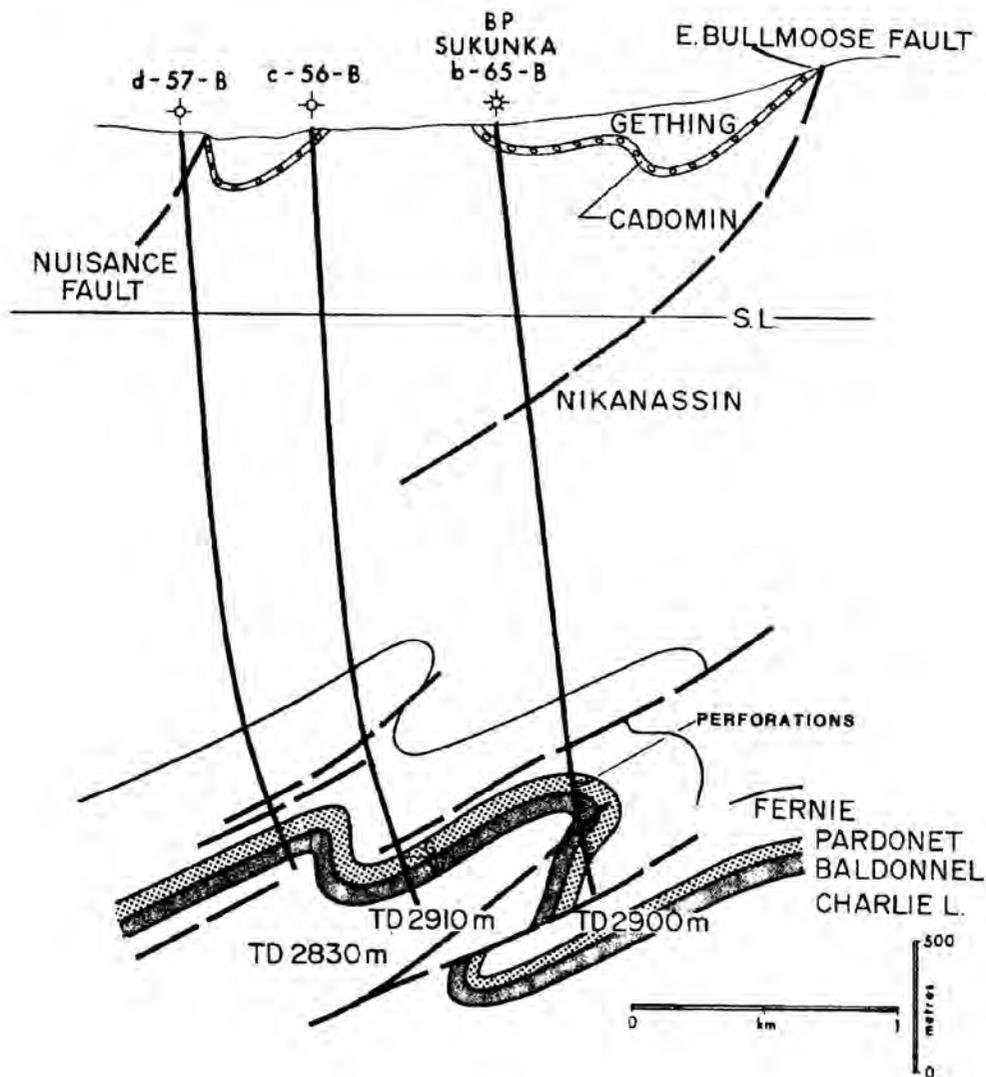
## Hydrocarbon Occurrences

There are numerous large, high-productivity gas pools within the Bullmoose/Sukunka play trend (Map 11). Some dry holes tested tight, as reservoir-quality fracture systems were not encountered. Many others flowed high-rate water. Similar patterns are observed for the two northern plays.

We conclude that even though the Pardonet/Baldonnel has two or three tight gas plays, they are all structurally-controlled. Water is a significant risk, as there is no regionally-extensive gas-saturated Deep Basin regime.

SW

NE



**Fig. 8.** Illustration of fracture-dominant Foothills structural play trend, Pardonet/Baldonnel. Well b-65-B/93-P-5 intersects Pardonet/Baldonnel section at the crest of an overturned fold at the leading edge of a thrust sheet, where fracturing has produced economic reservoir quality. Other wells encountered tight, non-fractured reservoirs (from Barass and Montandon, 1981).

## **HALFWAY / DOIG FORMATIONS (Middle Triassic)**

### Stratigraphy and Distribution

The Doig and Halfway Formations are genetically-related facies tracts of a prograding clastic coastal system. The Doig consists of offshore to lower shoreface shale, siltstone, and sandstone, with local growth fault-controlled sandstones. Halfway strata are more proximal shallow marine sandstones deposited along the western margin of the North American craton in a variety of environments, including barrier island, shoreface, and tidal inlet channels (Moslow et al., 2003) (Fig. 9).

Doig and Halfway strata can be mapped across the southern Deep Basin and Peace River Block areas, and reach a northern subcrop edge in 94G and H (Map 12). They are thickest in the southwest, and thin depositionally northward and eastward (Cross-section HFY-HFY'). Burial depths range from 1200 to 2600 metres in northern areas where most pools occur, but can exceed 3500 metres in the southern Deep Basin.

Numerous papers have been written on conventional Halfway and Doig reservoirs in Alberta and north of the Peace River Block in B.C. (e.g., Gibson and Edwards, 1990; Caplan and Moslow, 1999; Evoy, 1997; Willis and Moslow, 1994; Wittenberg, 1993), and outcrop equivalents in the B.C. Foothills have also been well documented (e.g., Zonneveld et al., 1997). However, very little work has been done on regionally extensive tight sandstones of the Halfway and Doig in the outer Foothills and southern Deep Basin (Map 12).

Zonneveld et al. (1998) described Halfway shoreface sands at Tommy Lakes as quartzose, well-sorted, trough to planar cross-stratified, very fine- to medium-grained sandstone. Similar facies characterize the Halfway shoreface in the southern Deep Basin (Core log 15; Photo 2-24, 2-25). Zonneveld et al. (1997) noted similar clastic strata, along with a bioclastic carbonate shoreface component, in outcrop equivalents along Williston Lake (Map 12). Throughout northeastern B.C., bioclastic debris accumulated in tidal channels within the Halfway, and generated conventional reservoir quality where leached (Core photo 2-26). Within the Doig Formation, clean sandstones are relatively rare, occurring principally within the localized anomalously thick sandstone bodies documented by Wittenberg (1993).

### Reservoir Description

Halfway/Doig reservoirs in Alberta and adjacent B.C. exhibit conventional reservoir quality in tidal channel and shoreface sands. At Tommy Lakes, shoreface sands have porosities of 3-12%, and permeabilities ranging between 0.1 and 3 md (Zonneveld et al., 1998). Reservoir quality is considerably poorer

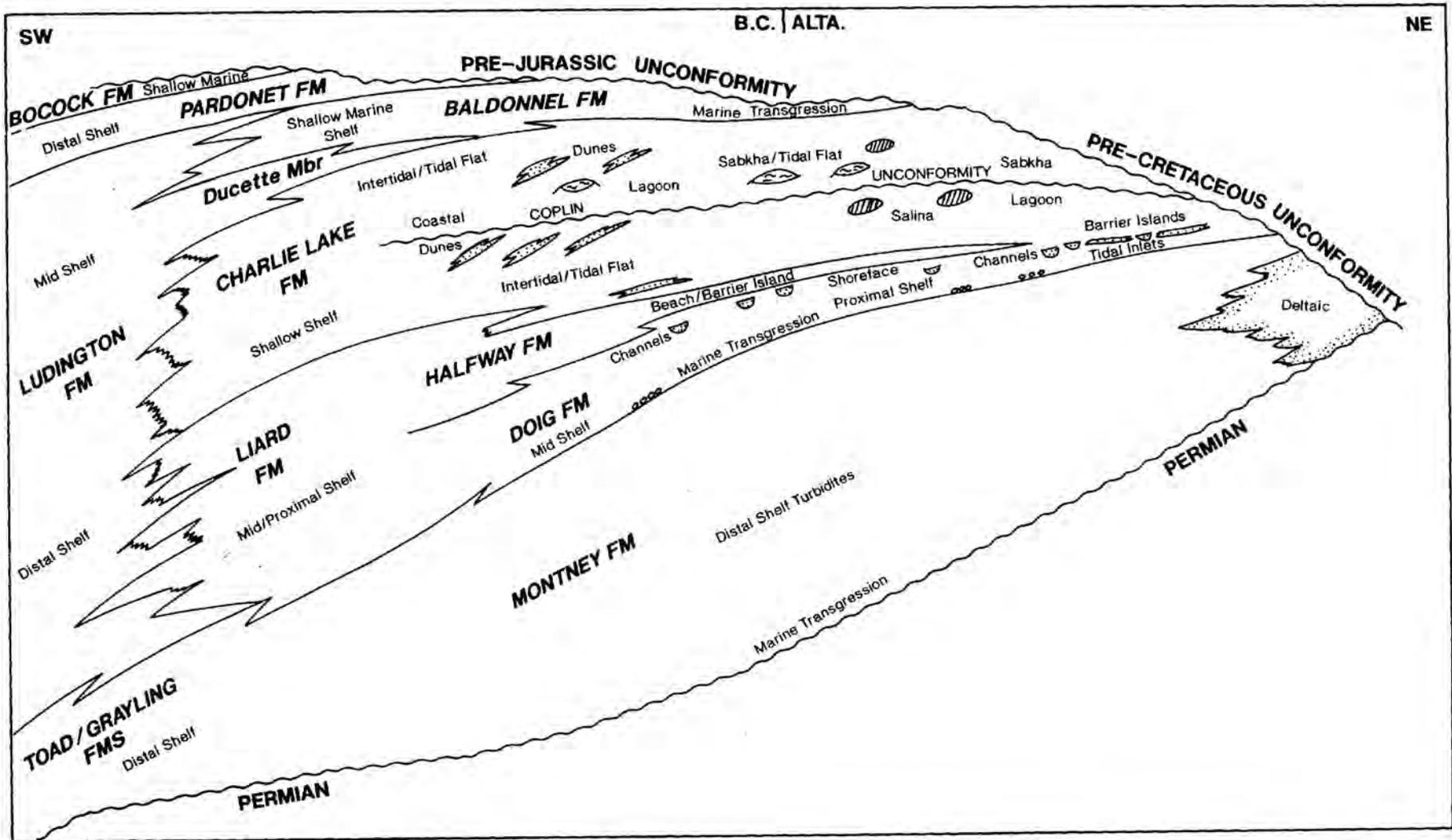


Fig. 9. Schematic cross-section illustrating Triassic formations, stratigraphic relationships, and depositional environments (from Gibson and Edwards, 1990).

where these rocks are more deeply buried, as at Monias and in the southern Deep Basin. Burial compaction, quartz overgrowths, and other cements (calcite, anhydrite) reduce reservoir quality, although chert and cement solution generates some secondary porosity (Photo 3-14). Leached bioclastic accumulations provide local sweet spots (Photo 3-15), but even these can be cemented tightly where buried more deeply.

Thick, brittle Halfway sandstone are likely enhanced by fracturing where structural deformation has occurred. This is likely the case at Redwillow/Grizzly North (93-I-15), where three Halfway wells have produced gas from depths of about 3900 metres (Map 12).

### Hydrocarbon Occurrences

There appears to be an area of Halfway pervasive gas saturation in the southern Deep Basin, but economic production has been achieved only where reservoirs are enhanced by fracturing. Updip of the Deep Basin limit line drawn on Map 12, water recoveries are much more common; for example, gas/water contacts exist at Monias. To the northwest, there is abundant Halfway production along linear fold trends; this is essentially the same play type as in the Baldonnel, where marginal reservoir quality is enhanced by fold-associated fracturing. At Tommy Lakes, moderate production from marginal-quality sandstones is augmented by more conventional reservoir quality in bioclastic channel sand sweet spots.

## **BELLOY FORMATION / STODDART GROUP**

(Permian – Upper Mississippian)

Belloy and Stoddart strata host a number of conventional plays, primarily within the Peace River Block, where these units form part of the upper Paleozoic fill of the Fort St. John Graben. They are not generally considered to be tight gas targets. However, recent gas discoveries in the Sukunka area (93-P-4) by Talisman and partners have been reported in industry newsletters as Permian, Pennsylvanian, and Mississippian producers, probably in fracture plays similar to the Pardonet/Baldonnel. To the south at Ojay (93-I-9), two wells have produced at high rates for short periods of time from the Taylor Flat Formation (part of the Stoddart Group), possibly from the same play.

The Permian and older section is very poorly known in this area, and there are no well data available from the most recent discoveries. We will review the exploration potential of this play in comparison to the Sukunka Pardonet/Baldonnel play.

## **MATTSON FORMATION (Upper Mississippian)**

### Stratigraphy and Distribution

Mattson strata in the Fort Liard area of the Northwest Territories consist of prodeltaic fine clastics, coarsening and becoming sandier upward, capped by deltaic and fluvial/floodplain strata (Photo 1-9). These grade basinward to Besa River shales to the southwest, in the Liard Basin of northeastern B.C. (Richards et al., 1993). The Mattson is preserved on the westward, downthrown side of the Bovie Lake Fault Zone, where it reaches up to 1400 metres near the northern depocentre, and in excess of 300 metres in B.C. (Map 13; Cross-section MAT-MAT'). Burial depths are in the 1000-1500 metre range in the northeastern Liard Basin, where reservoirs are best developed, but can exceed 2500 metres to the southwest. The Mattson grades conformably upward from basinal shales, but is capped unconformably by Permian or younger strata.

Although the Mattson has been documented in outcrop in several Geological Survey of Canada reports, little subsurface work has been done. Monahan (1999) presented several cross-sections and a short discussion, while Barclay et al. (1997) briefly outlined a Mattson structural play along the Bovie Lake Fault Zone.

Thick sandstones along the Bovie Lake Fault are massive to low-angle cross-bedded with mud clasts, containing locally abundant shell debris and abundant carbonaceous material (Core log 16; Photo 2-27). Grain sizes are predominantly very fine- to fine-grained. There are some interbedded grey to light green shales. Large vertical trace fossils characterize sandy beds. Westward, variably burrowed siltstones and shales dominate the succession (Photo 2-28).

### Reservoir Description

Mattson sandstones are typically quartzarenites, most very fine- to fine-grained, with minor chert, phosphate, and detrital carbonate grains. Silica is the primary cement, and calcite is locally abundant; pervasive pyrobitumen also occurs in some sections. Along the Bovie Lake Fault Zone, reservoir quality is locally very good, with porosities of more than 20%, and permeabilities up to hundreds of millidarcies (Core log 16, core analysis). Reservoir quality degrades quickly away from the sweet spots with greater burial depths, and where bitumen and carbonate cements are present (Photo 3-16). Where more cements do occur, the Mattson section is quite brittle, and exhibits fracturing in core. Overlying massive and bedded cherts of the Fantasque Formation may contribute to fractured reservoir potential (e.g. well a-78-L/94-O-10, Cross-section MAT-MAT').

Net clean sandstone mapping illustrates the concentration of Mattson sands along the Bovie Lake Fault Zone, although thicknesses up to 25 metres to the

west may represent the southwesterly fringe of the deltaic depocentre to the north (Map 13).

### Hydrocarbon Occurrences

Thick, high-quality Mattson sands produce gas from isolated structural traps at Windflower and Tattoo, while drillstem tests indicate high-permeability wet zones in offsetting locations (Map 13). At Beaver River (94-N-16), there is one gaswell and one water disposal well in the Mattson; fractures likely enhance reservoir quality in this structurally-deformed area. Low-rate gas flows have been recorded elsewhere, but there is not sufficient evidence to determine whether a gas-saturated Deep Basin regime exists.

## **JEAN MARIE MEMBER (Upper Devonian)**

### Stratigraphy and Distribution

The Jean Marie is a blanket shelf limestone, deposited in shallow marine settings under moderate energy conditions (McAdam, 1993). It varies from 10 to 20 metres thick across northeastern British Columbia, but thickens abruptly westward to a shelf margin up to 150 metres thick (Map 14). The Jean Marie is encased within Redknife/Fort Simpson basinal shales, and is buried 1000-1500 metres deep over the main exploitation areas, although it is deeper to the south (Fig. 10). McAdam (1993) noted that the Jean Marie western shelf margin is nearly coincident with the Slave Point carbonate bank edge in 94-P-5 and northward, while it parallels the Keg River carbonate bank edge further south, thus implying deep control on development of the Jean Marie shelf edge.

Documentation of the Jean Marie is sparse – Belyea and McLaren (1962) described it in outcrop in the Northwest Territories, while Law (1971) and McAdam (1993) have published regional overviews in the Northwest Territories and northeastern B.C. subsurface, respectively. Reinson et al. (1993) described regional Jean Marie play types and exploration potential.

Jean Marie strata comprise stacked biostromal accumulations, each up to 4.5 metres thick, consisting of tabular, stromatoporoid-coral framestone-bindstones. These biostromes are encased in lime mudstones-wackestones (Reinson et al., 1993) (Core log 17, Photo 2-29). Law (1971) speculated that the Jean Marie shelf edge thick is a trend of isolated reef buildups, analogous to Leduc buildups at the edge of the Cooking Lake platform.

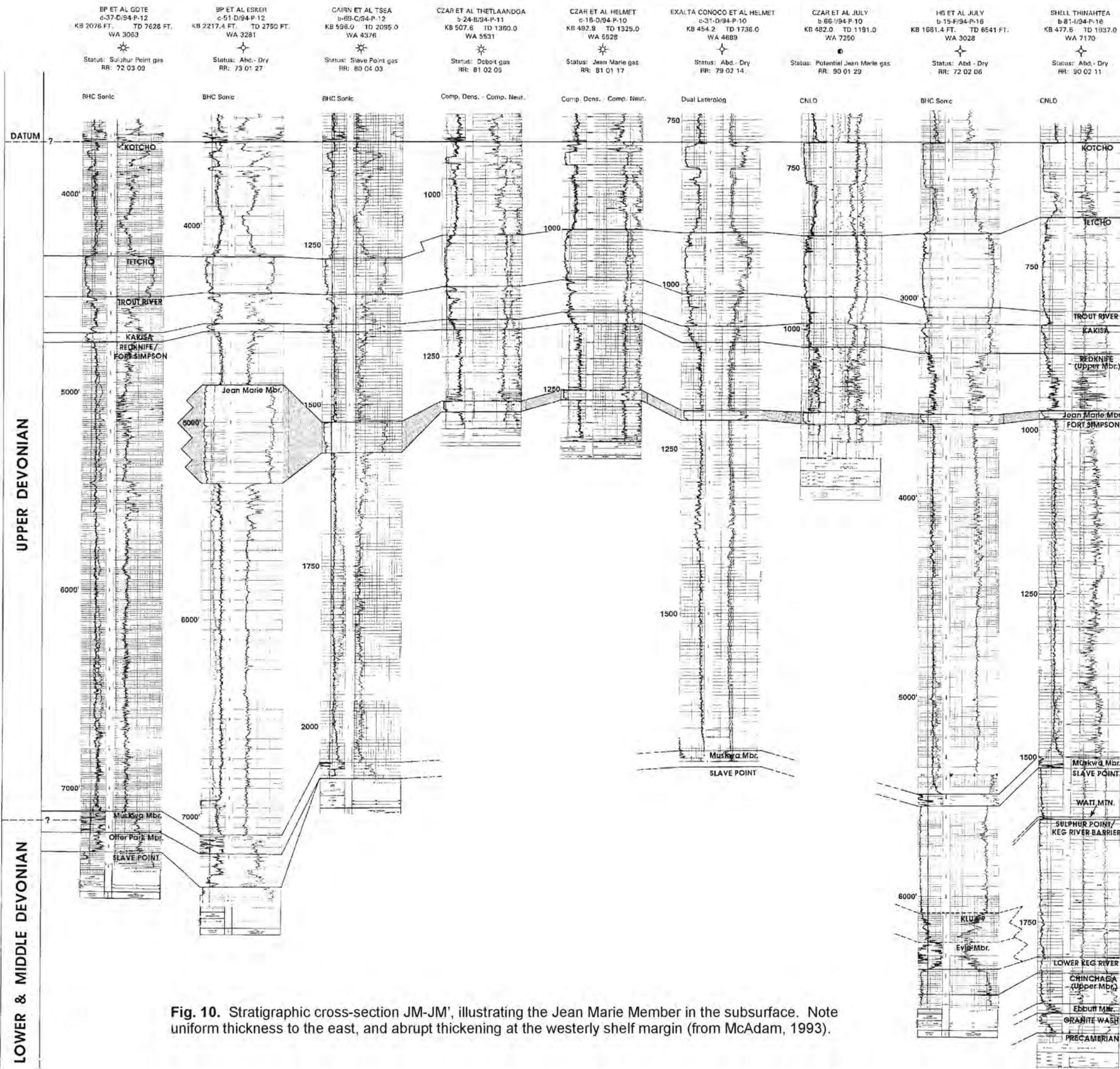


Fig. 10. Stratigraphic cross-section JM-JM', illustrating the Jean Marie Member in the subsurface. Note uniform thickness to the east, and abrupt thickening at the westerly shelf margin (from McAdam, 1993).

## Reservoir Description

Jean Marie porosity occurs as isolated vugs within reefal facies, limited intercrystalline/intergranular porosity in dolomites and calcarenites, and fractures. McAdam (1993) noted average porosities of 5.8% in established Jean Marie fields, average net pays of 6 metres, and water saturations ranging from 18 to 53% (generally increasing northward). Permeabilities are characterized as relatively low by Reinson et al. (1993), and do not exceed 0.1 md in core at c-12-E/94-I-1 (Core log 17).

Natural fractures are key to Jean Marie productivity. McAdam (1993) noted that fracture intensity is greater in more competent and dolomitized facies. Reinson et al. (1993) speculated that fracture intensity is greatest where the Jean Marie shelf and Fort Simpson shales are draped over Slave Point bank margins.

## Hydrocarbon Occurrences

Gas is the pervasive reservoir phase in the Jean Marie ; no formation water has been recovered. In addition, reservoirs are subnormally pressured, with an overall decrease in reservoir pressure northward towards outcrop (McAdam, 1993). The Jean Marie thus appears to be a basin-centered gas accumulation, according to the definition of Law (2002), but is geographically separate from the traditional Deep Basin area of the Western Canada Sedimentary Basin.

Map 14 illustrates widespread and areally-extensive Jean Marie production in northeastern B.C. Many wells have been drilled horizontally, in order to access natural fractures that enhance productivity. Note that while development and stepout drilling continues to expand the northern pools, which were brought on stream in the 1980's and 90's, most recent Jean Marie drilling has focused on new developments to the south at Gunnell Creek, Sierra, and Ekwan.

## **MIDDLE DEVONIAN AND OLDER STRATA**

There are very few penetrations of pre-Middle Devonian strata in northeastern British Columbia, and consequently, little is known of their reservoir characteristics or hydrocarbon potential. Two stratigraphic units may be of interest as potential tight gas targets:

1. Clastics shed from the Peace River Arch and Antler Orogeny highlands during Devonian time (and earlier) – analogous to the Granite Wash clastics in Alberta. Field work by Petrel Robertson suggests that these strata may be more quartzose in B.C., and hence might be tightly cemented where deeply buried.

2. Carbonates and clastics of the Proterozoic Muskwa assemblage are massive tight units, more than 2000 metres thick, where they crop out in the northern Rocky Mountains (94K) (Petrel Robertson, 1995). Deep seismic and magnetic/gravity work indicate that these strata subcrop beneath the deep Plains to the east, where structural deformation related to Antler orogenesis may have promoted fracturing (Petrel Robertson, 1993).

Thick Cambrian through Silurian strata crop out in the Rocky Mountains as well, but thin abruptly eastward. Most of this section pinches out within the outcrop belt, and there is likely very little preserved in the subsurface. In the pre-Elk Point Devonian section, gas potential occurs primarily within conceptual targets with conventional reservoir quality; we cannot document tight gas potential in these units.

## CARDIUM FORMATION

### Current Situation

The Cardium Formation is not an exploration target in B.C. Where it has been tested, it is as a secondary target, and often with a straddle drillstem test run on the basis of a prospective well log signature. The formation has thus been open to drilling fluids for an extended period of time, and wellbore damage is likely to be severe. This situation is exacerbated by lack of reservoir “sweet spots”, shallow drilling depths and subnormal formation pressures.

Velvet Exploration undertook an exploration program in 2000/2001 for fractured Cardium shoreface sandstones in the Copton-Narraway area of Alberta, in the southeastern corner of Map 2. There do not appear to be a substantial number of new Cardium wells on production in this area, and Velvet’s successor, El Paso, is not drilling new wells on the play.

### Tight Gas Potential

The Cardium presents an attractive in-place gas resource, with massive sandstones of substantial thickness distributed continuously over a large area (Map 2) (Table 1). Because of its shallow burial depth, there has been less reservoir degradation by compaction than for deeper tight gas reservoirs. However, low reservoir pressures reduce in-place gas volumes, particularly within the subnormally-pressured Deep Basin. By qualitative comparison with the Cadotte and Spirit River, we speculate an in-place gas resource of 1-3 BCF/section.

Cardium tight gas will likely be a secondary, uphole target to be exploited in conjunction with deeper tight gas plays. Locally, Cardium gas production may occur where:

- operators stumble upon conglomeratic sweet spots, or
- fracture-enhanced reservoir sections are defined in the Foothills, where the Cardium section is thickest.

**Table 1**  
**GAS RESOURCE POTENTIAL, TIGHT GAS RESERVOIRS, NORTHEASTERN B.C.**

FORMATION	RESOURCE RANGE (BCF/DSU)	PROSPECTIVE AREA (km <sup>2</sup> )	RESERVOIR CONTINUITY	TOTAL GAS RESOURCE RANGE (TCF)	COMMENTS
Cardium	1 - 3	4 000	High - shoreface	4 - 10	Deep Basin, shallow; little production
Dunvegan	1 - 3	7 000	Low - channels	7 - 15	Deep Basin, shallow; little production
Sikanni / Goodrich	<1 - 3+ (?)		High - shoreface; vertical barriers?	??	Foothills; little information
Scatter	??	11 000	High - shoreface; vertical barriers?	??	Liard Basin; no production
Cadotte	3 - 6	5 500	High - shoreface	16 - 25	Deep Basin; established strat. sweet spot production
Spirit River	3 - 12+	7 500	High - shoreface	20 - 50	Deep Basin; established strat. sweet spot production; multiple units
Bluesky (south)	1 - 4	5 000	Moderate - deltaic	5 - 10	Deep Basin; production from discontinuous basal Bluesky
Bluesky (north)	2 - 5	2 500	Moderate (?) - valley fill	5 - 10	Some production; fracture enhancement possible
Cadomin / Gething (south)	2 - 7	10 000	Moderate - alluvial fan / plain	20 - 50	Deep Basin; production to east; no strat. sweet spots in B.C.
Cadomin / Gething (north)	2 - 7	5 000	Moderate (?) - valley fill	10 - 20	Some production; fracture enhancement possible
Nikanassin (south)	??	10 000	Mixed - variety of environments	Large ??	Isolated production; Deep Basin and Foothills (fractured); very tight; very large gas in place
Buick Creek (north)	2 - 6	6 000	Moderate - deltaic	12 - 25	Fracture enhancement required - local fold trends
Pardonet / Baldonnel	3 - 20 (?)	12 000	Dependent on fracturing	35 - 100	Production from natural fractures assoc. with structure; water risk
Halfway / Doig	1 - 7	27 000	High - shoreface	25 - 100	Deep Basin and fracture-enhanced production; what is potential of thick tight sections?
Belloy / Stoddart	??	??	Dependent on fracturing	??	Production from natural fractures assoc. with structure; water risk
Mattson	<1 - 5 (?)	3000	High - shoreface / delta	1 - 10	Production from sweet spots along Bovie Fault and Foothills fractures; water risk
Jean Marie	1 - 10	28 000	Moderate - shelfal carbonates	25 - 100	Widespread production - moderate fracturing; no water
Middle Devonian / older	??	??	??	??	Unknown - thick regional subcrop; fracturing?

Values are estimated for order of magnitude comparison only. Gas resource refers to gas in place; no recovery factors assumed.

## **DUNVEGAN FORMATION**

### Current Situation

The Dunvegan has been explored only slightly more than the Cardium in B.C. Thin Doe Creek sandstones are conventional gas and oil producers at Kelly, and several wells have been drilled for them (Map 3). There has been virtually no exploration for the rest of the Dunvegan, however, as it shares several problems with the Cardium – shallow depths, lack of “sweet spots”, low formation pressures, and drilling damage.

Dunvegan sandstones produce from thick, tight, fractured reservoirs at Lynx in the Alberta Foothills, but there have been no further discoveries (and only limited development) on this play in the past 10 years.

### Tight Gas Potential

Dunvegan tight gas potential is less attractive than other Cretaceous targets, as reservoir distribution is much less continuous, prospective channelized trends have not been mapped regionally, and much of existing production is oil. Similar to the Cardium, the Dunvegan represents uphole secondary target potential, not a primary exploration target (Table 1).

Dunvegan tight gas may have economic potential locally where thick channel sandstones can be mapped, particularly if they occur where fracturing can enhance reservoir quality.

## **SIKANNI / GOODRICH SANDSTONES**

### Current Situation

Sikanni and Goodrich sandstones are not exploration targets at present. Penetrations are limited, as the sands are best developed close to the front of Foothills, where drilling is expensive because of deep targets, environmental sensitivities, and high access costs. The single gas completion at Bougie (Map 4) is intriguing, but has not yet driven further exploitation.

### Tight Gas Potential

There are thick potential reservoirs in the Sikanni and Goodrich, distributed over large areas of northeastern B.C. (Map 4) (Table 1). Interbedded shales substantially impair reservoir continuity and gas volumes at Bougie, although cleaner sandstones may occur in sections closer to the Foothills. As for the Cardium and Dunvegan, shallow burial depths and lack of “sweet spots” also

detract from their economic potential. There is no established Deep Basin regime, and faulting may breach potential Deep Basin pressure seals in the Foothills.

Sikanni/Goodrich tight gas potential may be realized in the future, in areas where other exploration activities have provided ready access to optimal reservoirs in the deep Plains and outer Foothills.

## **SCATTER FORMATION**

### Current Situation

Scatter reservoirs have not been evaluated systematically to date. Drilling in the Liard Basin has been very limited, except in the Maxhamish Field (Map 5). Even here, there have been very few Scatter tests, as wells have been targeted to develop the deeper Chinkeh reservoir. Scatter reservoirs are difficult to evaluate on well logs because of their heterolithic bedding.

### Tight Gas Potential

Scatter potential is an unknown, even more than the Sikanni and Goodrich (Table 1). Presence of hydrocarbons, either in conventional or Deep Basin accumulations, has not been demonstrated. There are no known “sweet spots”, and widespread fracture enhancement of reservoir quality appears unlikely. Nevertheless, widespread, lithologically similar Upper Cretaceous sandstones produce gas over large areas of southeastern Alberta and adjacent Saskatchewan.

A systematic uphole evaluation of the Scatter over the Maxhamish Field would help to quantify its productive potential. Elsewhere, lack of facilities and pipelines make Scatter plays uneconomic.

## **CADOTTE MEMBER**

### Current Situation

The Cadotte contains true regional tight gas potential. There is abundant production from conglomeratic sweet spots, and numerous moderate- to low-rate gas tests from coarse-grained strata with poor to moderate reservoir quality. Conventional fracture stimulations can produce low-rate gas flows from sub-millidarcy rock anywhere within the Deep Basin regime (Map 6). Natural fractures have likely enhanced reservoir quality at certain locations (e.g. c-63-G/93-I-15).

Current exploration programs target sweet spot plays with conventional reservoir quality. There has been no systematic effort to produce from Cadotte tight sands.

### Tight Gas Potential

Throughout the Deep Basin, tight Cadotte sandstones contain in-place gas resources comparable to sweet-spot reservoirs, as porosity of fine-grained tight sands is very similar to that of conglomerates (generally 6-10%), even though permeabilities are orders of magnitude lower. Gas-in-place is commonly calculated in the range of 3-6 BCF per drilling spacing unit, varying with reservoir pressure and thickness (Table 1). Considering conventional Cadotte gas alone (Alberta and B.C.), Stockmal et al. (2001) tabulated discovered gas-in-place at  $24,872 \text{ e}^6\text{m}^3$  (878 BCF) and gas to be discovered at  $43,265 \text{ e}^6\text{m}^3$  (1528 BCF). The tight gas resource base must be several times larger.

Because of its regional distribution, mappability, and huge in-place gas resource, the Cadotte is an ideal target for tight gas production using advanced drilling and completion techniques. Coarse-grained facies with poor to moderate reservoir quality are widespread, and offer more attractive potential than fine-grained, uniformly tight middle shoreface sandstones (Core log 4).

Well-developed production infrastructure in the prospective area is an additional positive economic factor.

## **SPIRIT RIVER FORMATION**

### Current Situation

Like the Cadotte, Spirit River shorefaces produce from conglomeratic sweet spots, and feature numerous low- to moderate-rate gas completions throughout the Deep Basin. Although a huge tight gas resource is recognized, exploration and production is focused entirely on conventional reservoirs.

### Tight Gas Potential

In-place gas resources for each shoreface unit of the Spirit River Formation compare closely to those of the Cadotte. Map 6 shows that total reservoir sandstones in the Spirit River are up to five times thicker than the Cadotte, however, as there are up to six stacked reservoir intervals (Table 1). Stockmal et al. (2001) tabulated discovered in-place gas at  $102,582 \text{ e}^6\text{m}^3$  (3623 BCF) for conventional Spirit River reservoirs, with  $28,888 \text{ e}^6\text{m}^3$  (1020 BCF) remaining to be discovered. The Canadian Gas Potential Committee figures are  $155,356 \text{ e}^6\text{m}^3$  (5514 BCF) and  $140,200 \text{ e}^6\text{m}^3$  (4976 BCF), respectively. The tight gas resource base will be several times larger than these figures.

Spirit River sandstones are thus also ideal targets for tight gas production using advanced drilling and completion techniques. As for the Cadotte, numerous Spirit River sections offer relatively attractive tight gas potential in coarse-grained, but conventionally subeconomic reservoirs (e.g. Core log 6). Interbedded coals provide local gas sources, and may even contribute to deliverability where appropriately fractured.

Burlington Resources announced upon taking over Canadian Hunter Exploration that they would exploit Deep Basin tight gas resources using techniques learned in the San Juan Basin (Daily Oil Bulletin, 02/06/18). Many observers thought these efforts would be directed toward Falher tight sandstones, but no such program has been unveiled to date.

## **BLUESKY FORMATION**

### Current Situation

Bluesky production in the southern Deep Basin is from isolated, discontinuous basal Bluesky sweet spots. Some basal Bluesky sections with marginal reservoir quality have yielded low-rate gas, but there is no production from widespread deltaic sandstones of the Chamberlain Member. A small number of exploration wells have targeted stratigraphic plays for basal Bluesky conglomerates.

In the Buick-Laprise Valley, scattered gaswells produce from sweet spots with conventional reservoir quality arising from one or more of: i) intergranular porosity in conglomerates; ii) secondary solution porosity in medium- to coarse-grained sandstones; or iii) fracture enhancement through structural deformation. The valley trend is lightly drilled, and discoveries have not been extensively developed, as operators are not confident that they understand the play. There have been no efforts to exploit the thick valley-fill sandstones with advanced drilling or completion technologies.

### Tight Gas Potential

Tight gas potential in the southern Deep Basin is limited by the argillaceous, heterolithic nature of the Chamberlain Delta sandstones, and discontinuous distribution of basal Bluesky facies (Table 1). Bluesky tight gas potential here is a secondary target to be evaluated between the more attractive Spirit River and Cadomin plays.

Bluesky valley-fill sandstones in the Buick-Laprise valley are more mappable, and offer in-place gas potential of several BCF per DSU, given greater reservoir thicknesses and porosities comparable to the Cadotte, but shallower burial depths. Locally, a Bluesky tight gas play might be economically attractive,

particularly where facilities are available and access costs are reasonable. Laramide fold crests would offer particularly attractive targets, so that risk of water is minimized, and potential for fracture enhancement maximized.

## **CADOMIN / GETHING FORMATIONS**

### Current Situation

Despite numerous gas tests in the southern Deep Basin, the Cadomin produces primarily along the updip Deep Basin edge in Alberta (production in B.C. at Kelly Lake is primarily from isolated Gething channels) (Map 9). Efforts to downspace and to drill directionally and horizontally have succeeded only in particular areas. In the 1990's, Canadian Hunter was forced to write down hundreds of BCF of tight gas reserves assigned to the Cadomin in the Alberta Deep Basin, as they were judged not to be economically accessible.

There is no production from fractured Cadomin sections in the B.C. Foothills, although the Cadomin is reportedly a component of the fractured reservoirs play that has been pursued for the past several years to the southeast at Copton / Narraway.

To the north, Cadomin/Lower Gething strata produce only at Kobes, where fracturing associated with folding and thrusting has probably enhanced reservoir quality. There have been no efforts to explore for Gething gas in the valley trends outlined on Map 9, although several gas and oil discoveries have been developed in conventional reservoirs within large valleys to the east.

### Tight Gas Potential

Much like the Cadotte and Spirit River, the Cadomin holds immense volumes of tight gas resources in the southern Deep Basin (Table 1). Porosities are generally lower, but the Cadomin section is continuous, and thickens substantially to the northwest (Map 9). Unfortunately, the Cadomin lacks reservoir sweet spots, and lies below most conventional Deep Basin targets. Thus, relatively few wells penetrate it. Horizontal wells are expensive and difficult to drill in the highly siliceous, poorly-sorted chert pebble conglomerates.

Thick, brittle Cadomin sections should be highly prone to fracturing in the Foothills, but lack of production to date makes future potential difficult to quantify. If the Cadomin is indeed a contributor to production at Copton / Narraway, the play should soon move northwestward into the Foothills of northeastern B.C.

To the north, thick lower Gething sands offer good reservoir potential, by tight gas standards. It would appear that the Gething has not been properly evaluated, particularly along the linear fold play that enhances reservoir quality in

several other reservoir units. Scattered water recoveries pose the risk of encountering water, but aquifers are likely to be structurally and stratigraphically discontinuous.

## **MINNES GROUP (NIKANASSIN / BUICK CREEK)**

### Current Situation

Nikanassin tight gas potential has not been explored in the southern Deep Basin. Like the Cadomin, it lacks mappable sweet spots, and it lies below many of the primary drilling targets. In the adjacent Foothills, production at Wolverine, Grizzly North and Grizzly South has been attained in wells drilled for the Pardonet/Baldonnel (Map 10). Nikanassin fractured tight gas reservoirs have been a primary target in recent drilling at Copton / Narraway, immediately east of the Alberta border, and that play is now beginning to move into 93-I-9.

To the north, tight Buick Creek sandstones are one of the targets in the outer Foothills linear fold belt trend. Although it has been exploited extensively near Blueberry, the Buick Creek has been eroded through the Beg/Jedney/Bubbles area, where Baldonnel and Halfway reservoirs are the prime targets.

### Tight Gas Potential

Nikanassin sandstones in the southern Deep Basin host tremendous tight gas potential. The Deep Basin fairway is very large, net clean sand thicknesses exceed 100 metres in many places, and deep burial leads to relatively high reservoir pressures. However, realization of this potential is not going to occur until operators identify drilling and completion technologies that can stimulate economic gas production from the very low quality rock.

In the southern Foothills, thick, brittle, fractured Nikanassin sections may host reserves comparable to the Pardonet/Baldonnel, if operators are able to map comparable appropriate structural configurations. Experience with completing the Nikanassin at Copton/Narraway should open up the entire southern B.C. Foothills trend to Nikanassin fractured gas production, although the pace of exploitation may be controlled at times by facilities constraints more than the productivity of the reservoirs.

Similarly, to the north, there are many linear fold structures which have been delineated, but which have not been adequately tested in the thick Buick Creek section. A major uncertainty is the ability of very tight quartzarenites in the Buick Creek west of Blueberry to produce nearly entirely from fractures. By comparison, the Baldonnel along this play trend has substantial matrix porosity to provide reservoir capacity.

## **PARDONET / BALDONNEL**

### Current Situation

Although the Bullmoose/Sukunka fracture-dominant play trend was discovered over 30 years ago, stepout and exploration drilling is still taking place. Improved seismic imaging, better structural models, and growth of infrastructure have driven expansion of the play fairway. During the past decade, significant reserve additions have been booked, particularly at Murray and Highhat Mountain (Map 11). Although not as prominent, the Cypress play area has also experienced steady activity, and reserves have grown markedly at Graham.

The Baldonnel linear fold play trend has been one of the consistently busiest areas in northeastern B.C. during the past decade. New structures have been defined, while all of the older fields have been extended. Multiple tight gas reservoir potential has been exploited with infill and twinned wells.

Despite this history, Baldonnel tight gas reserves and production growth has been slowed by seasonal access, environmental issues, aboriginal land title questions, and pipeline/facilities limitations.

### Tight Gas Potential

The Baldonnel is one of only two tight gas plays in northeastern B.C. (along with the Jean Marie) in which tight gas potential has been recognized and systematically exploited. There is abundant room in all three Baldonnel tight gas play fairways for additional discoveries and further exploitation, as summarized in NEB, GSC, and Canadian Gas Potential Committee projections:

National Energy Board, 1997:

- Baldonnel Grizzly: Discovered -  $53.5 \text{ e}^9\text{m}^3$ ; Potential -  $145 \text{ e}^9\text{m}^3$
- Baldonnel NW Foothills: Discovered -  $46.2 \text{ e}^9\text{m}^3$ ; Potential -  $27.2 \text{ e}^9\text{m}^3$

Stockmal et al. (2001) (GSC):

- Sukunka Triassic: Discovered -  $84.1 \text{ e}^9\text{m}^3$ ; Potential -  $184 \text{ e}^9\text{m}^3$
- Jedney Baldonnel: Discovered -  $34.3 \text{ e}^9\text{m}^3$ ; Potential -  $162 \text{ e}^9\text{m}^3$   
- includes Graham play area; all figures raw gas in place

Canadian Gas Potential Committee (2001):

- Sukunka: Discovered -  $100.5 \text{ e}^9\text{m}^3$  ; Potential -  $76.9 \text{ e}^9\text{m}^3$   
- includes other reservoirs – Halfway, Charlie Lake, Belloy
- Graham: Discovered -  $36.4 \text{ e}^9\text{m}^3$ ; Potential -  $27.5 \text{ e}^9\text{m}^3$   
- includes other reservoirs – Debolt, Halfway
- Linear fold belt play trend – not specifically recognized

## HALFWAY / DOIG FORMATIONS

### Current Situation

Halfway sandstones are targeted in conjunction with other tight to moderate-quality reservoirs (Bluesky, Gething, Cadomin, Buick Creek, Baldonnel, Mississippian) along linear fold trends in the Kobes/Beg/Bubbles fairway in the northern Foothills (Map 13). This play has been drilled actively during the past several years, and numerous trends remain to be fully exploited.

Officially tabulated gas in place at Tommy Lakes has decreased dramatically during the past decade ( $1993 - 19,247 \text{ e}^6\text{m}^3$ ;  $2001 - 12,518 \text{ e}^6\text{m}^3$ ), as marginal reservoirs on the fringes of the pool are no longer recognized as productive. At Monias, the assigned recovery factor was decreased from 90% to 60%, as the result of poor pool performance (National Energy Board, 2000). In both cases, low-permeability Halfway sandstones are not delivering gas at economic rates from conventional wellbores. There is no documentation of systematic efforts to exploit marginal Halfway reservoirs with advanced drilling or completion technologies.

Halfway exploration in the southern Deep Basin has occurred at low levels during the past decade. Although there are several interesting shows, commercial production has not been attained.

Doig reservoirs are conventional producers in isolated pools on the Peace River Plains, but show no tight gas prospectivity in the deeper Plains and Foothills areas.

### Tight Gas Potential

Halfway tight sands contain immense gas resources in the deep Plains and outer Foothills (Table 1).

In the short to medium term, established reserves will continue to increase in the linear fold belt play trend as more structures are exploited, and as targeting of

optimal fracture configurations improves. Rising gas prices and availability of infrastructure should support reserves additions through horizontal drilling and advanced completions in marginal reservoirs within and surrounding large pools such as Tommy Lakes and Monias.

In the long term, high-impact gas potential exists in two areas:

- advances in drilling and completion technology sufficient to make deep tight sands in the southern Deep Basin economically accessible.
- successful application of the Pardonet/Baldonnel fractured Foothills play model to the Halfway, thus opening up the entire thrust outer Foothills trend
  - the NEB (1997) tabulated  $0.36 \text{ e}^9\text{m}^3$  established reserves in the Halfway Grizzly Foothills play, but projected that  $33.9 \text{ e}^9\text{m}^3$  remained to be discovered

## **BELLOY FORMATION / STODDART GROUP**

As noted previously, recent (2002) high-deliverability gas discoveries at Sukunka (93-P-4) by Talisman and partners have been reported as occurring within Belloy/Stoddart strata, with possible contribution from Mississippian rocks (Debolt Formation?). To the south, two BP Canada wells at Ojay (93-I-9) tested high-rate gas from the Taylor Flat Formation; b-57-G/93-I-9 flowed  $585 \text{ e}^3\text{m}^3/\text{d}$  over a period of 24 days. Several outpost and exploration wells are active in both areas.

Talisman has estimated reserves of 20-40 BCF/well, with 25 locations identified on the Sukunka play (Daily Oil Bulletin, 03/01/15). We speculate that this play is analogous to the Pardonet/Baldonnel Sukunka play, but taps into brittle, fractured reservoirs stratigraphically deeper. Further information will be required to verify this idea.

The NEB (1997) identified a Belloy – Grizzly Foothills play, to which they assigned only  $0.27 \text{ e}^9\text{m}^3$  established reserves, but projected that  $19.5 \text{ e}^9\text{m}^3$  remained to be discovered. This estimate appears conservative in light of recent discoveries.

The structurally-deformed, fractured tight reservoir play model that has been successfully exploited in the Pardonet/Baldonnel for more than 30 years is clearly applicable to other stratigraphic units with similar physical properties. Because of the need to target very specific structural configurations in order to ensure optimal fracturing, the geographic distribution of reserves at different stratigraphic levels will vary considerably.

## **MATTSON FORMATION**

### Current Situation

Thick sandstones with conventional reservoir quality host most Mattson reserves and potential in structural traps along the Bovie Lake Fault Zone (Map 13; Barclay et al., 1997). However, production from upper Mattson tight sands and associated Fantasque chert at Tattoo (a-78-L/94-O-10) and at Beaver River (d-73-K/94-N-16) establish fractured reservoir potential in this unit.

There is no active exploration program for Mattson tight gas potential. Limited outpost and development drilling does occur along the Bovie Lake Fault, with conventional Mattson sands as one of the targets.

### Tight Gas Potential

Tight Mattson sandstones occur as distal deltaic facies across northeastern 94N and adjacent 94O (Map 13), and productive potential should occur wherever fracturing has taken place in response to structural deformation. This appears most likely in outer Foothills structures such as Beaver River (K/94-N-16).

There are no data to support projections of Mattson tight gas resource potential.

## **JEAN MARIE MEMBER**

### Current Situation

The Jean Marie is an active and highly prospective gas play in northeastern B.C. To the north, pools discovered and initially developed during the late 80's and early 90's continue to expand, with current reserves several times higher than those tabulated ten years ago. To the southwest, EnCana Corporation describes the Greater Sierra gas field as a "world-class discovery", with more than 5 TCF of gas in place (Daily Oil Bulletin, 03/01/15). Since entering the play in 1998 (as Alberta Energy Company), EnCana has built a two million acre (net) land base, and claims an inventory of 600 drilling locations. Although attention has been focused on the Jean Marie shelf margin (at Gunnell Creek), stepout and development drilling is also taking place at Sierra and Ekwan to the east (Map 14).

Horizontal drilling has traditionally been seen as the best way to access fractured tight gas reservoirs of the Jean Marie, and was the key to the expansion at Helmet, Midwinter, and Peggo-Pesh in the 1990's. At Greater Sierra, EnCana's wells feature horizontal legs of up to 1000 metres, and are drilled underbalanced with nitrogen foam to avoid formation damage and water phase traps that would reduce productivity (Daily Oil Bulletin, 03/01/15).

## Tight Gas Potential

The Jean Marie contains by far the largest accessible tight gas resource in British Columbia. The entire Jean Marie shelf fairway is prospective, and current technology is sufficient to develop much of it.

Economics will determine the pace of discovery and exploitation. Now that EnCana has established the Greater Sierra play, the entire shelf margin play trend is available. Gas in place ranges from 5 to 10 BCF (140-280 e<sup>6</sup>m<sup>3</sup>) per square mile (drilling spacing unit). In winter 2002/2003, EnCana is running 30 rigs in the area, has deliverability exceeding 150 MMCF/D (4250 e<sup>3</sup>m<sup>3</sup>/d), and has booked reserves in excess of 600 BCF (17 e<sup>9</sup>m<sup>3</sup>). Total gas in place is predicted to exceed 5 TCF (142 e<sup>9</sup>m<sup>3</sup>). On the Jean Marie shelf to the east, gas in place figures are lower because of thinner pays and shallower burial, but the play continues to grow with advancing drilling and completion technology, and continued growth of pipeline and facilities infrastructure.

It is interesting to note that Reinson et al. (1993) tabulated discovered in-place gas volumes of 11.6 e<sup>9</sup>m<sup>3</sup> (410 BCF) for the Jean Marie, and ultimate potential of 24.0 e<sup>9</sup>m<sup>3</sup> (849 BCF), numbers which are dwarfed by the potential of the Greater Sierra play. Similarly, established reserves in the Jean Marie Helmet play in 1997 (14.9 e<sup>9</sup>m<sup>3</sup>) exceeded the ultimate resource potential estimated in 1992 (14.3 e<sup>9</sup>m<sup>3</sup>), because of the success of horizontal drilling technology (National Energy Board, 1997). New play concepts and advancing technology have clearly revised our analysis of Jean Marie prospectivity.

## **MIDDLE DEVONIAN AND OLDER STRATA**

There are no data to support tight gas exploration potential in pre-Middle Devonian strata. However, thick Proterozoic carbonate and clastic units subcropping beneath the Plains offer intriguing conceptual targets. Two primary mechanisms may exist to produce tight gas potential:

1. Reservoir fracturing, relating to Antler orogenic movements. Petrel Robertson (1995) noted Antler-generated fracturing in outcrop, and speculated that this might extend to the subsurface.
2. Limited carbonate reservoir enhancement through karst formation or hydrothermal dolomitization.



# ANALOGUE BASINS AND PLAYS

## DEEP BASIN

Law (2002) classified the WCSB Deep Basin as a “direct-type” basin-centered gas accumulation, characterized by gas-prone source rocks and low-permeability sandstone reservoirs. In comparing analogous basins around the world, Law identified four reservoir pressures cycles during the development of basin-centred gas systems. The Canadian Deep Basin lies between Phase II, where gas generation has produced overpressured, gas-saturated reservoirs with little free water, and Phase III, where uplift, erosion, and cooling has produced underpressured accumulations. Although some Deep Basin reservoirs, such as the Viking and Belly River, exhibit well-defined downdip overpressured regions and updip underpressured regions, many others (e.g., Cadotte, Spirit River) are completely underpressured, and thus match the Phase III definition most closely.

The best analogues for the WCSB Deep Basin are the Cretaceous basin-centered gas accumulations of the western United States. Source and reservoir rocks were deposited in similar settings, and experienced a similar chronology of burial, maturation, and fluid migration. Law (2002) noted that the San Juan, Raton, and Denver Basins are underpressured, Phase III direct systems, and Popov et al. (2001) provided systematic descriptions of these basins. Individual reservoirs, such as the Muddy Sandstone of the Denver Basin (Higley et al., 2003) compare closely with units such as the Cadotte and Spirit River.

The reader is referred to the extensive reference lists compiled by Law (2002) and Popov et al. (2001) for more detailed information.

## FOOTHILLS

Fractured Pardonet/Baldonnel reservoirs of the B.C. Foothills are extensively documented in terms of reservoir quality, fracture development, and exploitation. Most other highly-fractured, low-porosity, high-productivity reservoirs described in the literature, such as the Austin Chalk of the southeastern U.S., occur in much different tectonic settings. However, two examples stand out as good analogues for the Pardonet/Baldonnel and related reservoirs:

- Jurassic Twin Creek Limestone of the Foothills (overthrust belt) of Wyoming and Utah. Bruce (1988) described these widespread, low-porosity shelfal carbonates, deformed by six major tectonic events, most notably thrust faulting. It appears unlikely that sophisticated structural

- models have been developed, as Bruce noted that “predictability of Twin Creek reservoirs is low”.
- Cretaceous Viking conglomerates of the Ricinus Field in west-central Alberta. Halwas et al. (1999, 2001) documented structure, compartmentalization, and fracturing in these low-porosity, brittle chert conglomerates and sandstones, and identified optimal drilling strategies.

## **NORTHERN PLAINS**

As an underpressured basin-centered gas accumulation, the Jean Marie shares many characteristics with Deep Basin reservoirs. Law (2002) noted only one example of a BCGA carbonate reservoir, in the Sichuan Basin of China. Law was likely unaware of the Jean Marie, as it has not been clearly documented in the literature in terms of basin-centered gas.

# EXPLOITATION STRATEGIES FOR TIGHT GAS RESERVOIRS

Tight gas exploitation in British Columbia (and elsewhere in Canada) lags years behind the United States. The United States Geological Survey first assessed unconventional gas resources in 1995, and is currently producing updated descriptions and resource assessments by basin (Popov et al., 2001; Lang, 2002). The most recent Canadian resource assessment reports, by Stockmal et al (2001) and the Canadian Gas Potential Committee (2001), do not address unconventional gas plays, other than to acknowledge that they exist.

Advances in B.C. tight gas exploitation will occur in two areas: applying more varied exploration and exploitation strategies, and systematically using modern drilling and completions technologies.

## EXPLORATION / EXPLOITATION STRATEGIES

Two major tight gas exploration and exploitation strategies account for most recent tight gas production increases in the United States, but have not been pursued systematically in Canada. Successful application of these strategies will require use of the advanced drilling and completion methods described below.

1. Pursuit of extremely thick basin-centered gas sandstones, with in-place gas resources ranging up to hundreds of BCF per section. Successful exploitation of these plays allows considerable downspacing and yields long-life reserves, thus improving project economics (see Lyle (2002), Norris and Phillips (2002), and Cumella et al. (2002)).

Although the southern Deep Basin contains large areas of thick stacked tight gas sandstones, there has been no concerted effort to exploit these, as economic production rates have not been attained outside of reservoir sweet spots. Downspacing has been applied in selected cases in low- to moderate-permeability strata where economic flow rates can be attained (e.g. Cardium and Cadomin sands in the Alberta Deep Basin).

2. Detection and exploitation of natural fracture “sweet spots” in settings with little structural deformation. This approach has been described for Cretaceous reservoirs of the Piceance Basin by Decker and Klawitter (1994) and Cumella et al. (2002), and for the Frontier Formation in the Green River Basin (Krystinik, 2001). Hart and Teufel (2000) described the detection of high-permeability fracture swarms in Mesaverde Group sandstones of the San Juan Basin.

In British Columbia, natural fractures are pursued primarily in highly-deformed Foothills settings. However, more subtle fracture systems enhance productivity in the Jean Marie, and have been mapped in relation to deeper carbonate platform edges (McAdam, 1993; Reinson et al., 1993). Intensive mapping of fracture trends, such as described by Hart and Teufel (2000), may yield sweet spots in other B.C. tight gas reservoirs.

## **MODERN DRILLING AND COMPLETION TECHNOLOGY**

Advances in drilling and completion methods allow operators to drill wells with much less formation damage, and to stimulate tight zones more successfully.

1. Directional and horizontal drilling – This has become a relatively common approach in exploiting tight gas reservoirs. Horizontal wells can open up long sections of marginal-quality reservoir, access stratigraphic sweet spots more readily, intersect large numbers of natural fractures with near-vertical orientations, and drain larger areas.

Directional drilling is now commonly used in B.C. to exploit fractured Foothills reservoirs, such as the Pardonet/Baldonnel. Horizontal wells are responsible for making much of the Jean Marie reservoir economic, and are also used in the linear fold belt play trend for the Baldonnel and other reservoirs. The NEB et al. (2000) analyzed horizontal well performance for selected plays in B.C., and demonstrated its economic value in most applications attempted to date.

2. Underbalanced drilling – This is another drilling strategy that has become relatively commonplace, and is often used in tandem with directional and horizontal drilling. Low-density drilling fluids, employing hydrocarbons, foams, emulsions, and air, are designed to prevent extensive filtrate invasion of reservoirs, thus avoiding or reducing formation damage.

EnCana has used inert nitrogen foam in wells with 1000 metre horizontal legs to access Jean Marie gas in its Greater Sierra play area (Daily Oil Bulletin, 03/01/15).

3. Advanced Fracture Stimulation – Sophisticated fracture stimulation jobs are the key to making many tight gas targets flow at economic rates. Lyle (2002) detailed the evolution of frac jobs in the Lance and Fort Union sandstones at Jonah Field in Wyoming. Fluids, proppants, timing and placement are all important issues in ensuring successful, long-lived reservoir stimulations.

As EnCana has been involved in much of this work in the U.S. Rocky Mountains, the technology will likely be applied more extensively in western Canada in the near future. Other U.S.-based operators, such as Burlington Resources, have stated their intention to apply U.S. tight gas technology to Canada's tight gas sands; fracture stimulations are an obvious area of interest.



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APPENDIX 1

## Outcrop Photographs

(select to view outcrop photos)

# OUTCROP PHOTOS

**Photo 1-1**

**Photo 1-2**

**Photo 1-3**

**Photo 1-4**

**Photo 1-5**

**Photo 1-6**

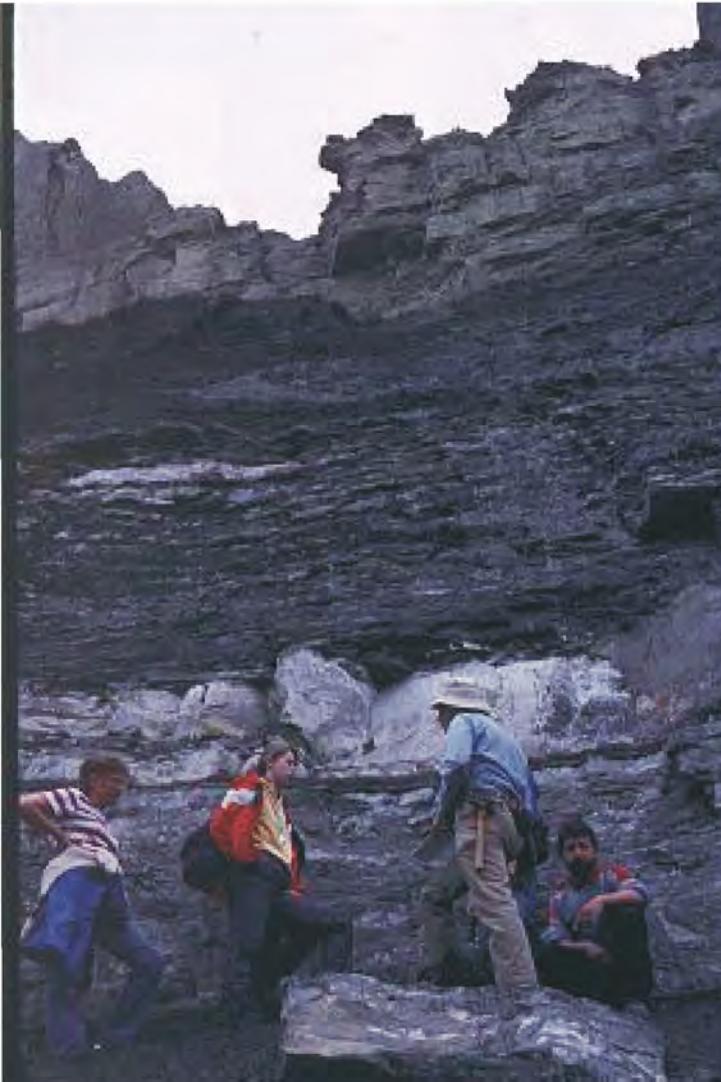
**Photo 1-7**

**Photo 1-8**

**Photo 1-9**



**Photo 1-1:** Cardium Formation, Bay Tree location (Twp. 78-13W6, Alberta). Moderately- to well-sorted conglomerates and coarse sandstones capping coarsening-upward shoreface succession. Low-angle cross-stratification defines the swash zone in the upper shoreface to foreshore setting.



**Photo 1-2:** Kaskapau Formation, near Pouce Coupe, Alberta. Thin shoreface/shelfal sandstones within the Kaskapau shales record the final regressive pulses of the Dunvegan deltaic complex.



**Photo 1-3:** Boulder Creek Formation (Cadotte equivalent), Mount Chamberlain, B.C. Foothills near Tumbler Ridge. Large-scale cross-stratification characterizes this channelized section, and is highlighted by interbedded conglomeratic and sandy beds.



**Photo 1-4:** Lower Spirit River equivalent strata, Mount Spieker, B.C. Basinal shales (Wilrich equivalent) at base grade up into stacked coarsening-upward shoreface to channelized successions within Falher-equivalent strata. The prominent cliff is the Falher F unit; the capping resistant unit "consists of Falher D conglomerates.



**Photo 1-5:** Falher D equivalent, Mount Spieker B.C. Conglomeratic lenses and beds in middle to upper shoreface sandstones.,



**Photo 1-6:** Cadomin Formation, Mount Belcourt, B.C. Alluvial fan conglomerates are more than 100 metres thick at this depocentre.



**Photo 1-7:** Gething Formation, along Peace River just below W.A.C. Bennett Dam. Thick continental mudstones and sandstones dominate the section.



**Photo 1-8:** Gething Formation, near W.A.C. Bennett Dam. Resistant channel sandstones stand out in generally recessive, muddy section.



**Photo 1-9:** Mattson Formation, Jackfish Gap type section, west of Fort Liard, Northwest Territories. Tan/grey Mattson deltaic sandstones lie on grey Flett Formation.



APPENDIX 2

## **Core Photographs**

(select to view individual core data)

# CORE PHOTOS

<b>Photo 2-1</b>	<b>Photo 2-16</b>
<b>Photo 2-2</b>	<b>Photo 2-17</b>
<b>Photo 2-3</b>	<b>Photo 2-18</b>
<b>Photo 2-4</b>	<b>Photo 2-19</b>
<b>Photo 2-5</b>	<b>Photo 2-20</b>
<b>Photo 2-6</b>	<b>Photo 2-21</b>
<b>Photo 2-7</b>	<b>Photo 2-22</b>
<b>Photo 2-8</b>	<b>Photo 2-23</b>
<b>Photo 2-9</b>	<b>Photo 2-24</b>
<b>Photo 2-10</b>	<b>Photo 2-25</b>
<b>Photo 2-11</b>	<b>Photo 2-26</b>
<b>Photo 2-12</b>	<b>Photo 2-27</b>
<b>Photo 2-13</b>	<b>Photo 2-28</b>
<b>Photo 2-14</b>	<b>Photo 2-29</b>
<b>Photo 2-15</b>	



**Photo 2-1:** Cardium Formation -- Top of shoreface (Kakwa Member). Alluvial plain silty mudstones lie on shoreface to backshore sandstones. Note roots in upper backshore.

Imperial Uno-Tex Windsor a-3-B/93-P-1, 933.7-934.5 metres.



**Photo 2-2.** Cardium Formation -- Medium- to coarse-grained, cross-bedded upper shoreface sands lie sharply and are loaded upon swaley cross-stratified, very fine-grained middle shoreface sands.

a-3-B/93-P-1, 941.3 metres



**Photo 2-3:** Cardium Formation -- Medium-grained sandstone, upper shoreface. Prominent *Macaronichnus* burrows are typical of the high-energy upper shoreface setting.

a-3-B/93-P-1, 937.2 metres



**Photo 2-4.** Sikanni Sandstone -- Very fine- to fine-grained, wavy-bedded with grey shales. Pervasive light burrowing obscures but does not destroy primary bedding.

Suncor Bougie a-85-A/94-G-15, 783 metres.



10

**Photo 2-5.** Sikanni Sandstone -- Localized slumping/soft sediment deformation destroys bedding in on thin interval

a-85-A/94-G-15, 787 metres.



**Photo 2-6.** Cadotte Member -- Swaley cross-stratified, very fine- to fine-grained middle shoreface sandstone.

Canhunter et al Jackpine c-14-F/93-P-7, 1861.5-1862.8 metres.



**Photo 2-7.** Cadotte Member -- Cross-bedded medium- to coarse-grained sandstones and conglomerates, upper shoreface.

Canhunter Noel b-24-A/93-P-7, 2057.8-2059.4 metres.



**Photo 2-8.** Cadotte Member -- Cadotte foreshore to backshore sandstones, overlain by thin coal, grading up to floodplain siltstone and mudstone. Note rooting in uppermost Cadotte sandstones.

b-24-A/93-P-7, 2049-2052 metres.



**Photo 2-9.** Cadotte Member -- Moderately- to poorly-sorted upper shoreface conglomerate. Note finer sands and pore-filling white clays reducing intergranular porosity.

b-24-A/93-P-7, 2056.6 metres.



**Photo 2-10.** Cadotte Member -- Well-sorted foreshore very coarse-grained sandstone to granule conglomerate. This rock is the best reservoir, as there is relatively little finer sand and clay to occlude porosity.

b-24-A/93-P-7, 2054.5 metres.



**Photo 2-11.** Cadotte Member -- Poorly- to moderately-sorted, cross-bedded upper shoreface strata, with pebbles confined to isolated beds. Compaction and silica cementation has significantly reduced reservoir quality.

c-14-F/93-P-7, 1851.6-1853.1 metres.



**Photo 2-12.** Cadotte Member -- Upper shoreface to lower foreshore sandstone, completely lacking a pebble component, and dominated by *Macaronichnus* burrows. Compaction and silica cementation has significantly reduced reservoir quality.

c-14-F/93-P-7, 1850 metres.



**Photo 2-13.** Falher B -- Upper shoreface coarse sandstone and conglomerate, relatively well-sorted, good reservoir quality.

Esso Windsor b-2-H/93-P-1, 2201-2202.6 metres.



**Photo 2-14.** Falher A -- Upper shoreface sandy conglomerate and pebbly sandstone, relatively poorly sorted, reduced reservoir quality.

b-28-G/93-P-1, 2338.25-2339.5 metres.



**Photo 2-15.** Falher A -- Middle shoreface swaley cross-stratified very fine-grained sandstone, very poor reservoir quality.

Canhunter Union Kelly b-28-G/93-P-1, 2347 metres.



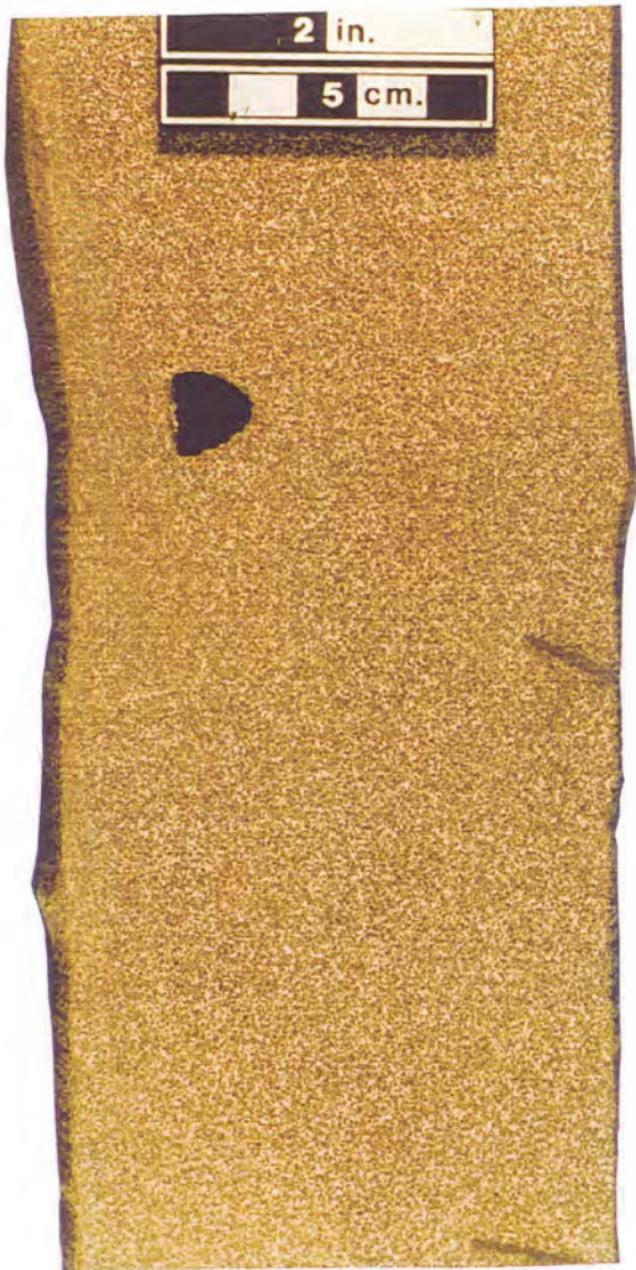
**Photo 2-16.** Basal Bluesky -- Plant fragments on parting surface near top of coarsening-upward delta/shoreface sandstone.

Canhunter Noel d-73-D/93-P-8, 2382.6 metres.



Photo 2-17: Basal Bluesky -- Mud clast breccia in channelized delta front sandstones.

Canhunter et al Noel b-18-E/93-P-8, 2395-2396.4 metres.



**Photo 2-18:** Bluesky valley fill -- Massive, homogeneous upper fine-grained sandstone. Alignment of two thin flat mud clasts suggests low- to moderate-angle cross-bedding. Cryptobioturbation in an estuarine setting may have obscured any bedding originally present.

UPRI Tarragon Laprise a-65-A/94-G-8, 1306 metres.



**Photo 2-19:** Bluesky valley fill -- Chert pebble conglomerate, well-sorted bed-by-bed. Imbricated pebbles, sorting, and low-angle bedding indicate extensive reworking, probably in an estuarine channel setting.

PCI Wargen d-56-C/94-H-6, 1140.5 metres



**Photo 2-20:** Cadomin Formation -- Poorly-sorted conglomerate, lacking clear bedding features or vertical stratigraphic trends. Large rounded chert clasts float in sandstone matrix.

Canhunter Esso Steeprock d-68-K/93-P-1, 2612-2613.4 metres.



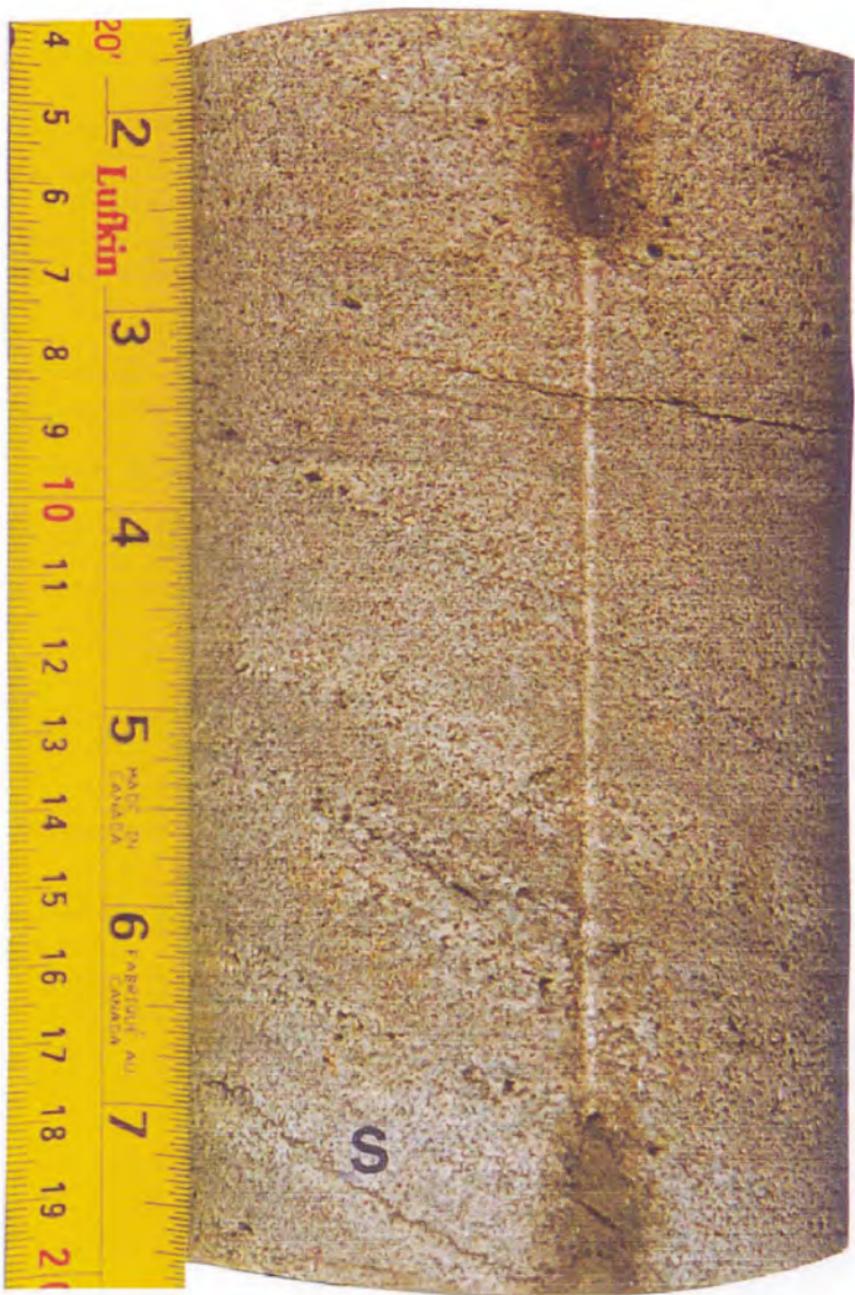
**Photo 2-21:** Nikanassin Formation -- Homogeneous, low-angle cross-bedded channel sandstones.

Canhunter et al Cutbank a-23-H/93-P-8, 2234-2235.2 metres.



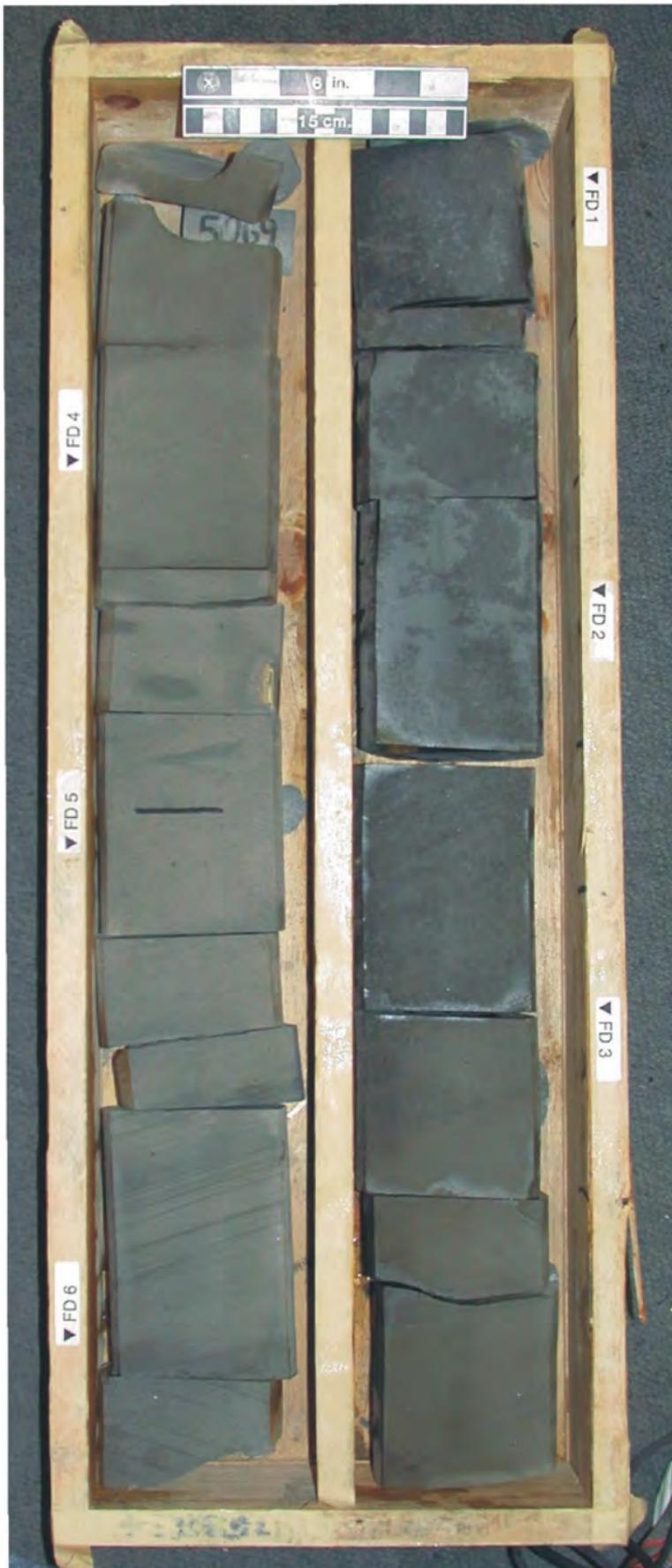
**Photo 2-22:** Nikanassin Formation -- Homogeneous, massive to vaguely low-angle cross-bedded sandstone. Note small floating mud chips.

a-23-H/93-P-8, 2236.9 metres.



**Photo 2-23:** Buick Creek sandstone -- Quartzarenite, trough cross-bedded, fine- to coarse-grained, moderately sorted bed-by-bed. Lithic and woody fragments have been leached out, creating isolated moldic pores. Bedding-parallel stylolite (S) is a result of compaction and pressure solution.

Coseka et al Gundy a-8-H/94-B-16, 4427.5 feet.



**Photo 2-24:** Halfway Formation -- Very fine-grained shoreface sandstones, mottled with anhydrite cements to top, grading down to well-laminated, cross-bedded facies.

AEC Tupper d-99-1/93-P-8, 2587-2588.5 metres.



Photo 2-25: Halfway Formation -- Heterolithic, wavy-bedded interval in Halfway shoreface.

d-99-1/93-P-8, 2595.2 metres.



**Photo 2-26:** Halfway Formation -- Bioclastic sandstone within tidal channel fill, note good moldic porosity.

PEX Norcen Horn d-55-A/94-G-9, 1371 metres.



**Photo 2-27:** Mattson Formation -- Quartzarenite, very fine-grained. Minor coarser grains align to highlight low-angle bedding.

Aquitaine et al Tattoo a-78-L/94-O-10, 2495 feet



**Photo 2-28:** Mattson Formation -- Siltstone to very fine-grained sandstone, interbedded with mudstone; originally bedding overprinted by pervasive bioturbation, particularly large vertical forms.

IOE Dunedin d-75-E/94-N-8, 11003 feet



**Photo 2-29:** Jean Marie Member -- Interbedded grey nodular limestone and tan bioclastic calcarenite. Note abundant fossil debris, including coral colony at bottom left.

Scurry Westcoast Ring c-12-E/94-I-1, 1515.5-1516.9 metres.



APPENDIX 3

## **Photomicrographs**

(select to view individual core data)

# PHOTOMICROGRAPHS

**Photo 3-1**

**Photo 3-2**

**Photo 3-3**

**Photo 3-4**

**Photo 3-5**

**Photo 3-6**

**Photo 3-7**

**Photo 3-8**

**Photo 3-9**

**Photo 3-10**

**Photo 3-11**

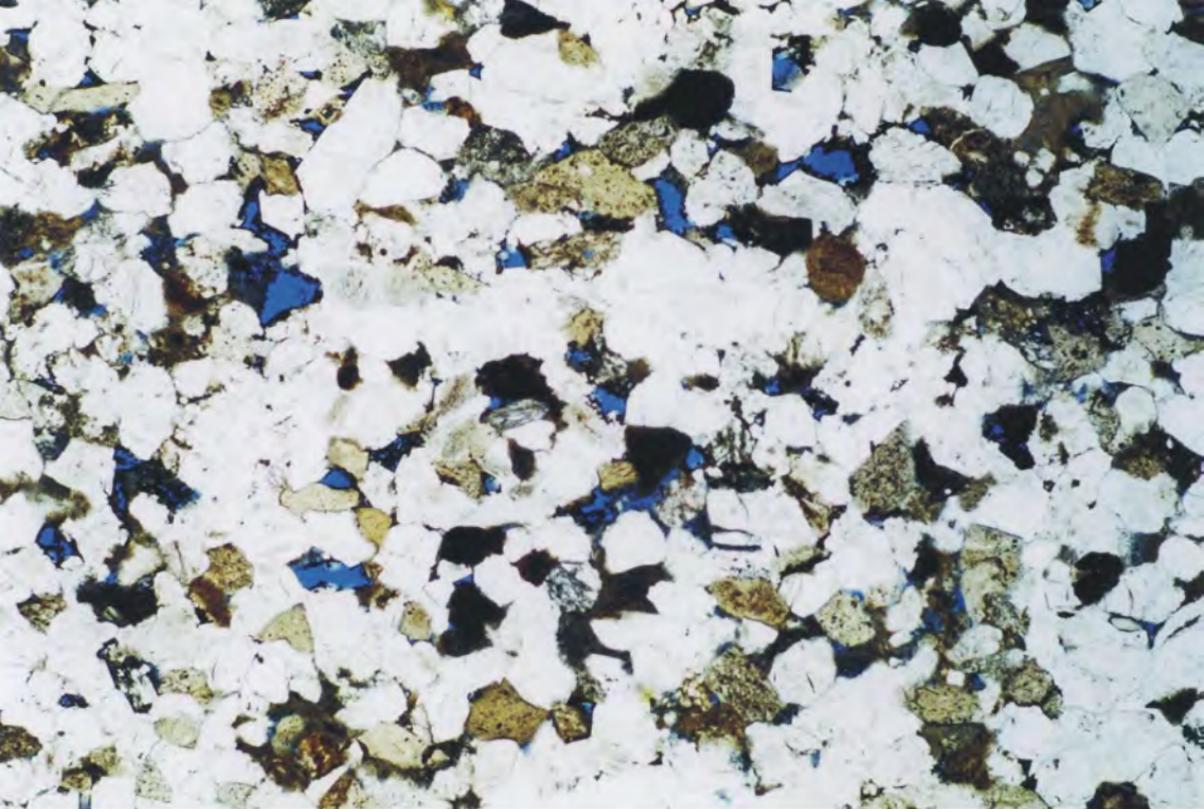
**Photo 3-12**

**Photo 3-13**

**Photo 3-14**

**Photo 3-15**

**Photo 3-16**



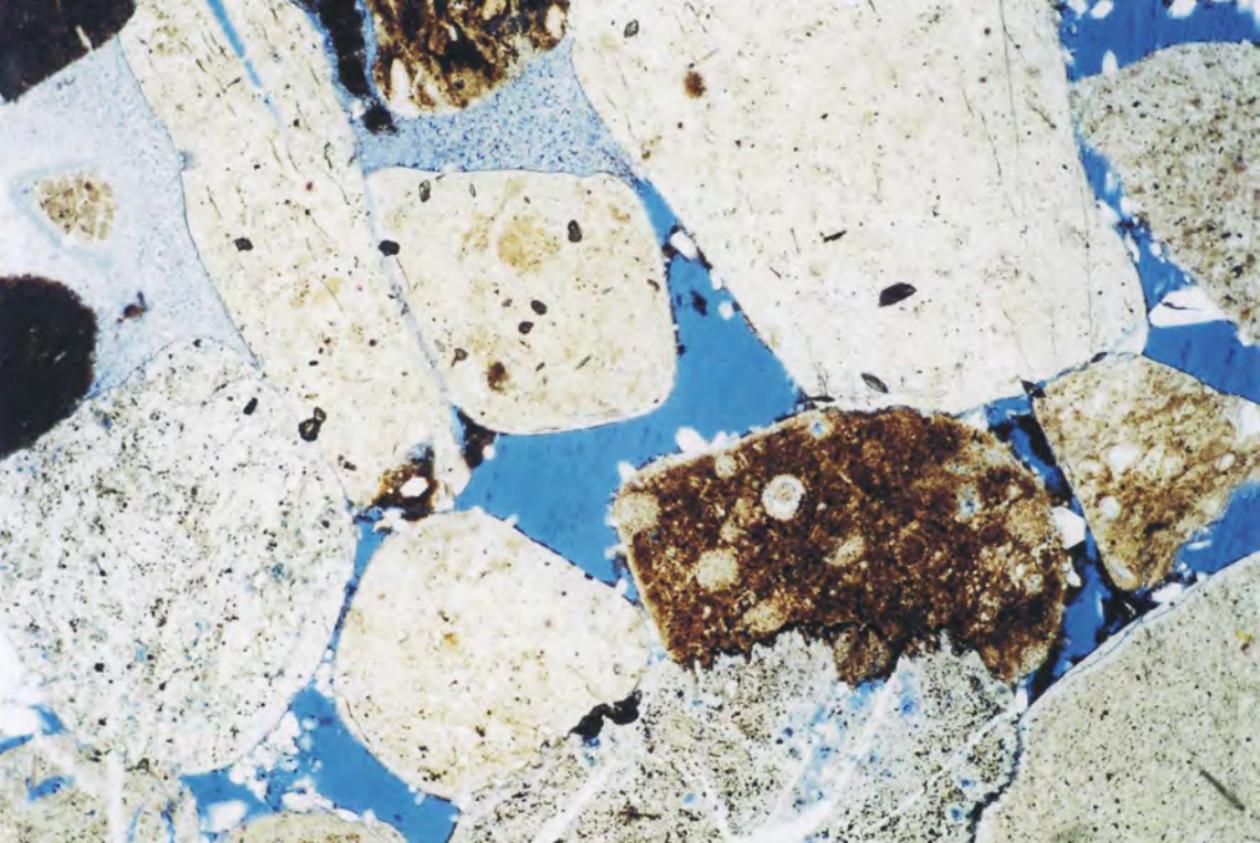
**Photo 3-1:** Cardium Formation -- Quartz-chert litharenite, very fine upper to medium-grained, moderately sorted. High compaction and extensive quartz overgrowths have greatly reduced effective porosity.

Imperial Uno-Tex Windsor a-3-B/93-P-1, 938.7 metres.



**Photo 3-2:** Sikanni Sandstone -- Quartz-chert litharenite, silt to lower fine-grained. Abundant matrix clays degrade poor reservoir quality.

Suncor Bougie a-85-A/94-G-15, 781.5 metres.



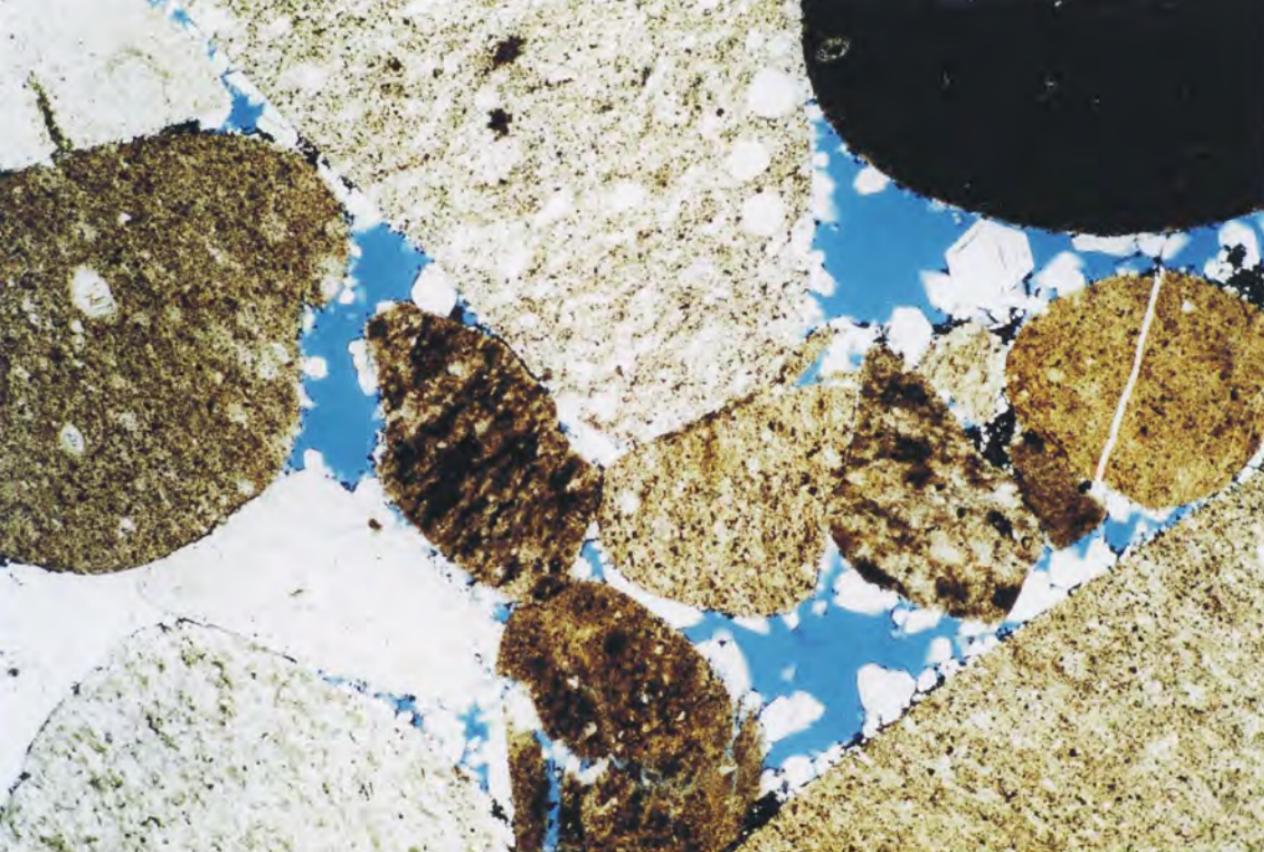
**Photo 3-3:** Cadotte Member -- Chert litharenite, very coarse-grained sandstone to granule conglomerate. Excellent primary intergranular porosity, with minor drusy quartz crystals.

Canhunter Noel b-24-A/93-P-7, 2054.3 metres.



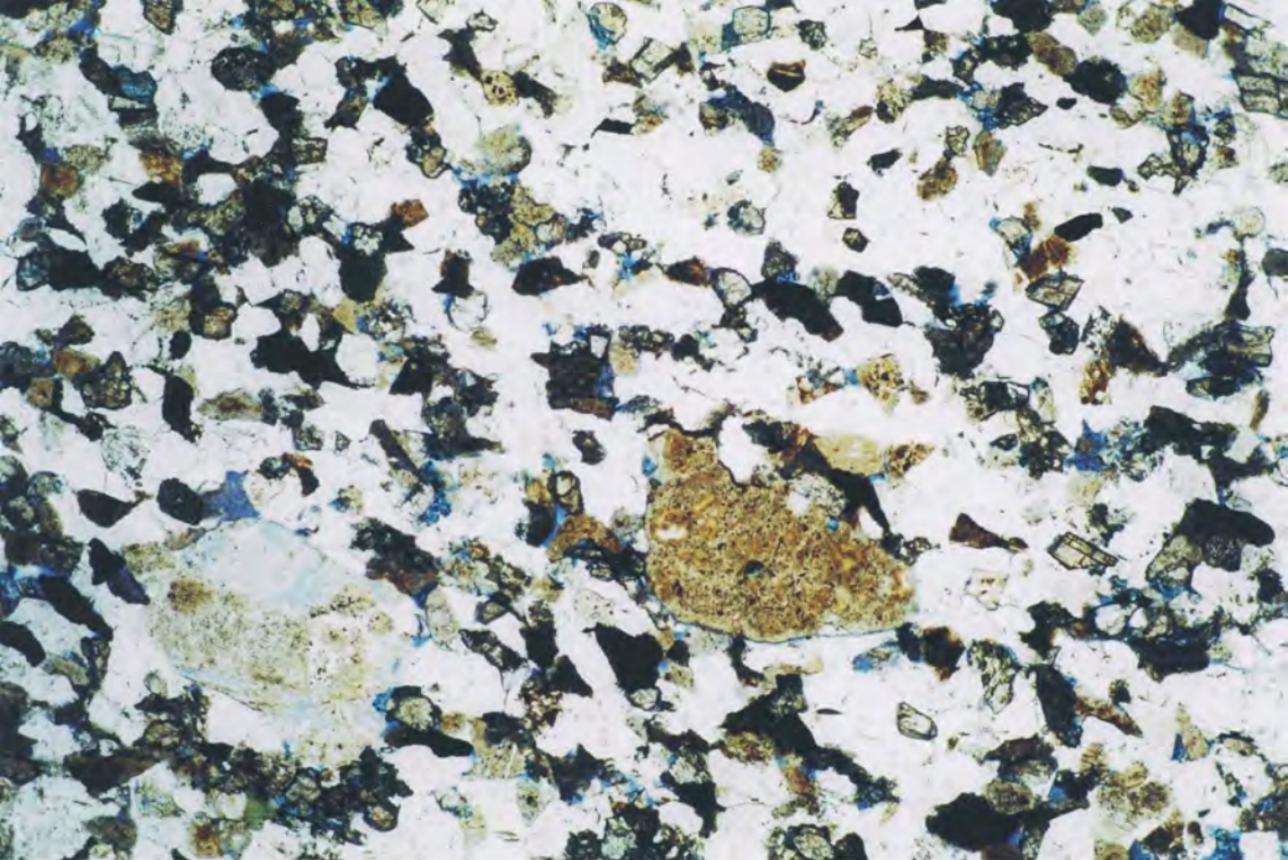
**Photo 3-4:** Cadotte Member -- Chert litharenite; most porosity is occluded by poor sorting, quartz overgrowths, and kaolinite cement.

Canhunter et al Jackpine c-14-F/93-P-7, 1850.5 metres.



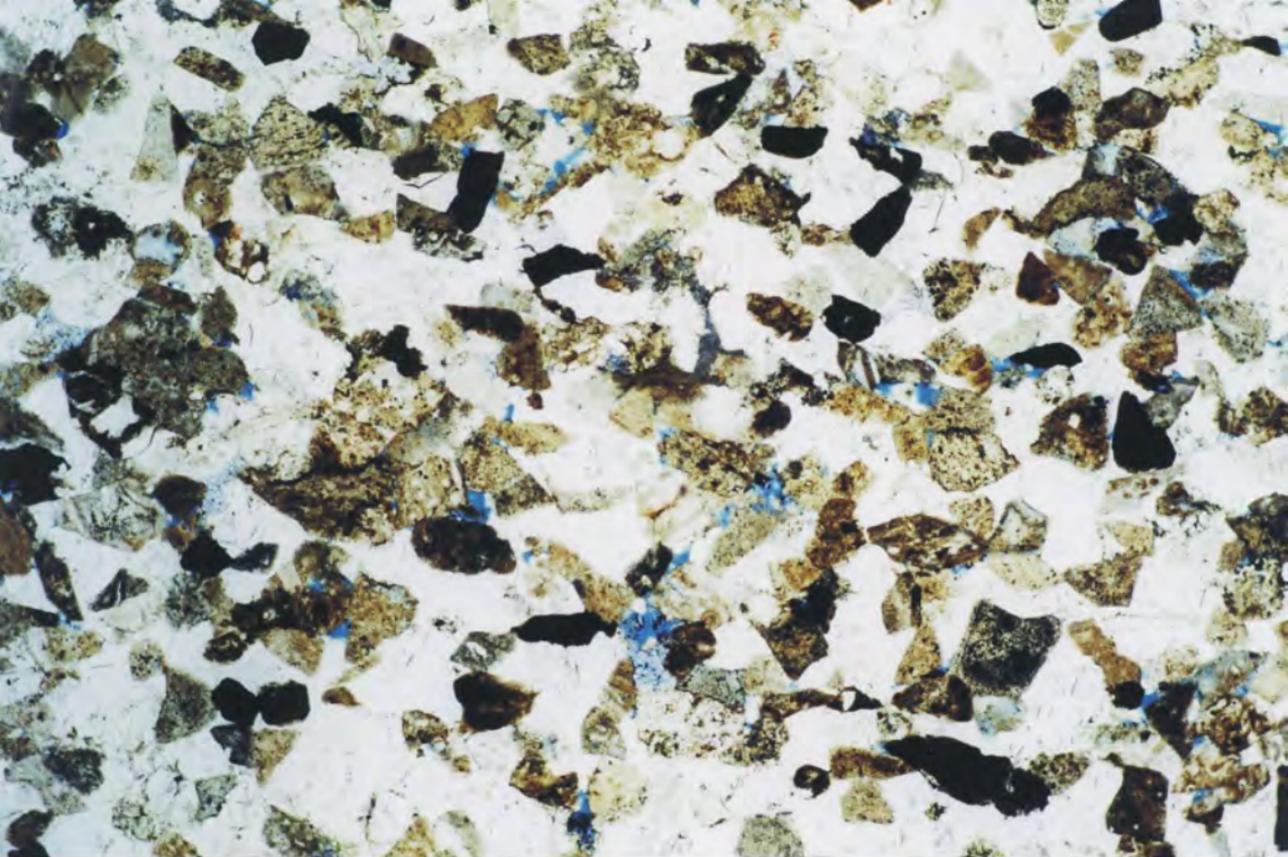
**Photo 3-5:** Falher B -- Chert litharenite; well-developed primary intergranular porosity, reduced to some extent by quartz crystals and compaction.

Esso Windsor b-2-H/93-P-1, 2100.4 metres



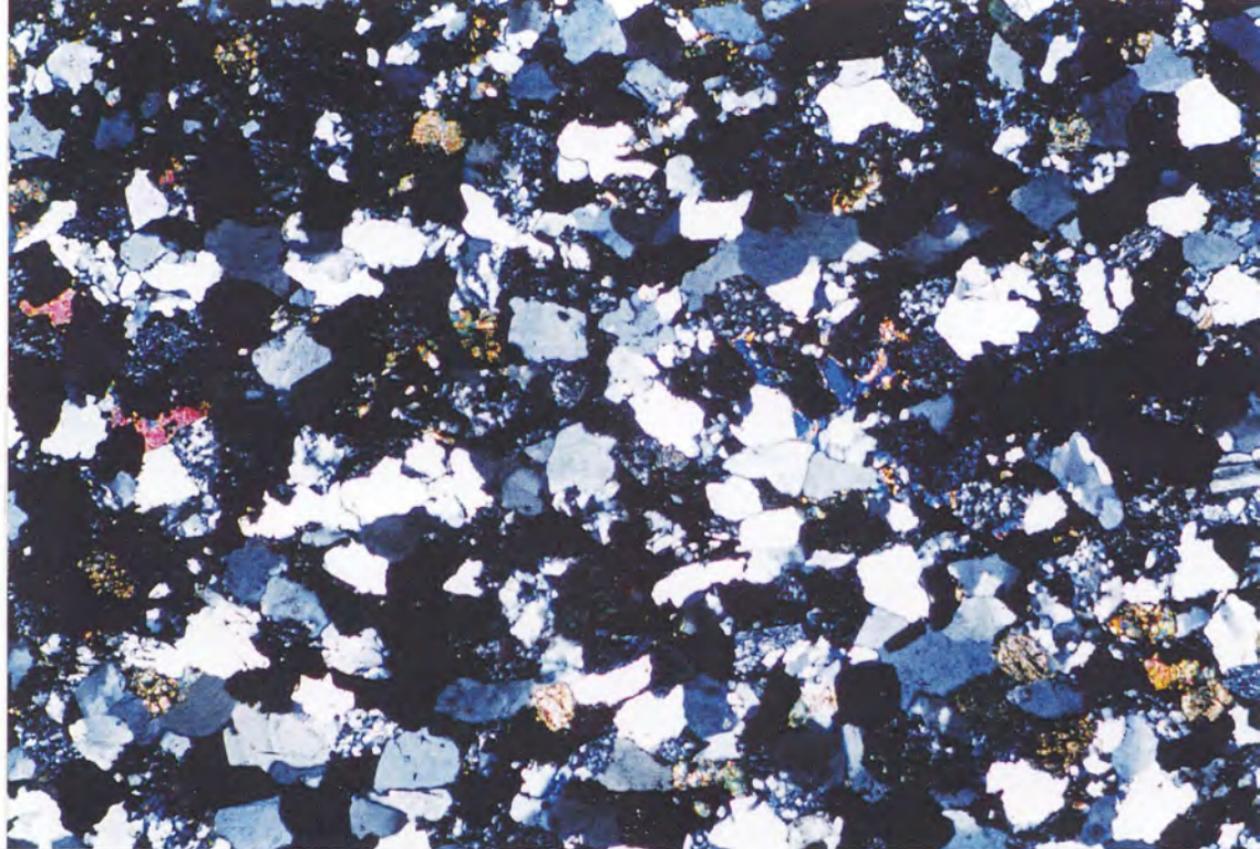
**Photo 3-6:** Falher A -- Litharenite; poor reservoir quality in very fine-grained middle shoreface sandstone. Note dolomite cement further reducing reservoir quality.

Canhunter Union Kelly b-28-G/93-P-1, 2343.5 metres



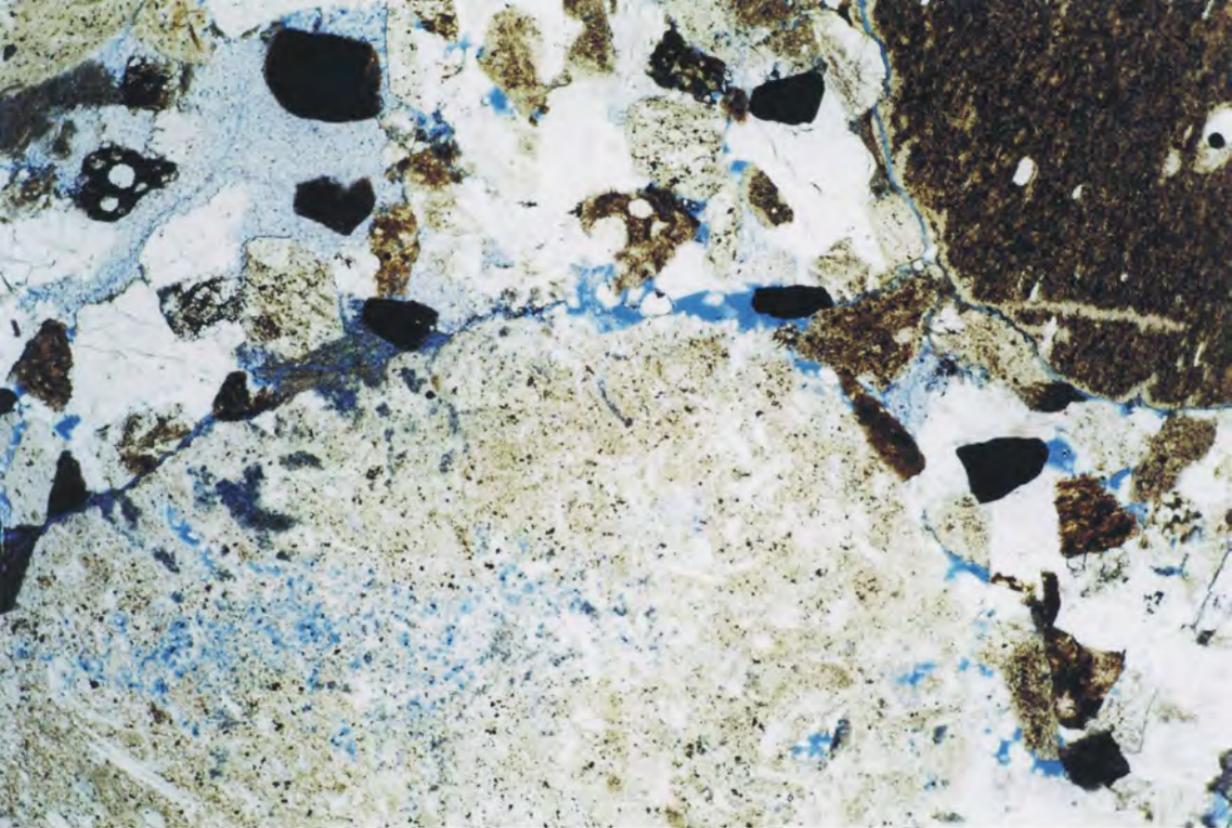
**Photo 3-7:** Basal Bluesky -- Litharenite; compaction and quartz cementation has degraded fine intergranular porosity.

Canhunter Noel d-73-D/93-P-8, 2382 metres.



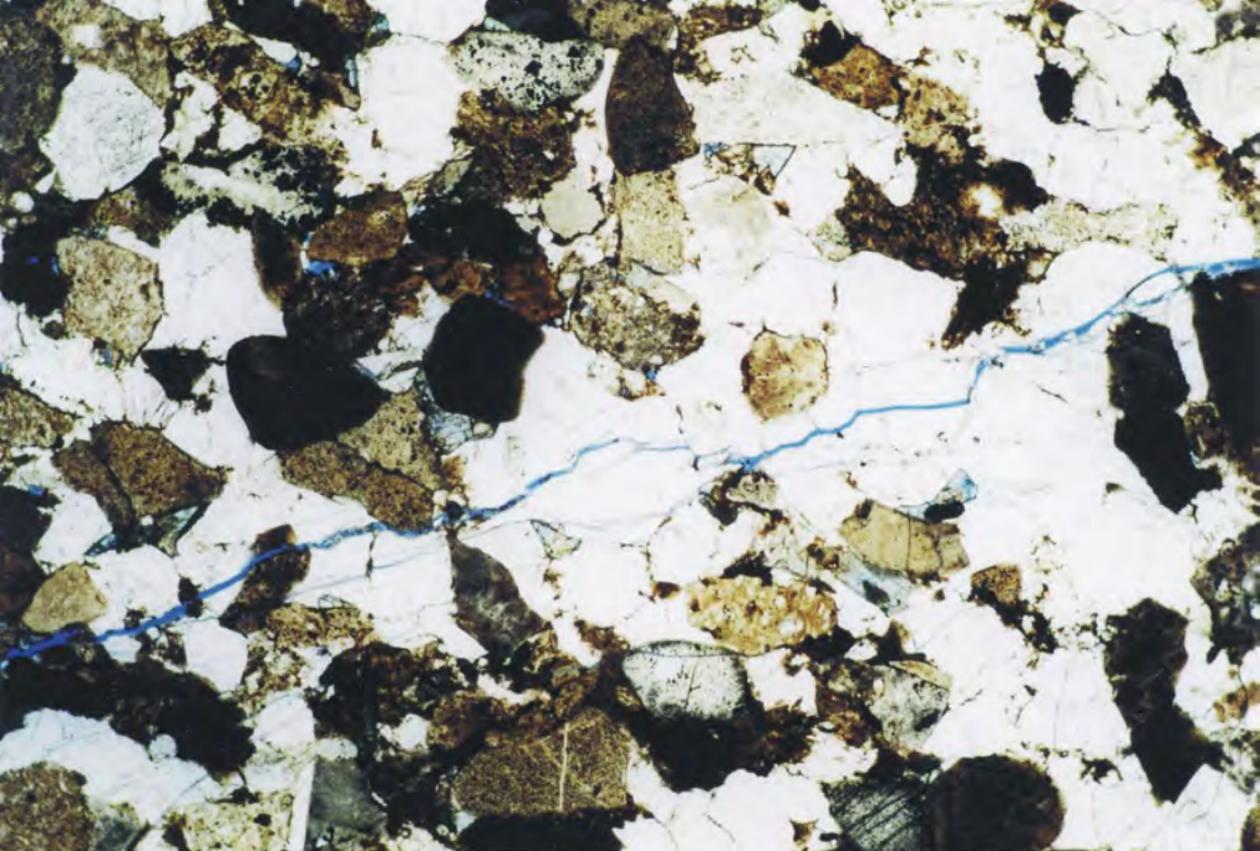
**Photo 3-8:** Bluesky valley fill -- Chert litharenite; porosity is almost completely occluded by compaction and quartz and carbonate cements.

Canhunter Town c-89-G/94-B-16, 1325.5 metres.



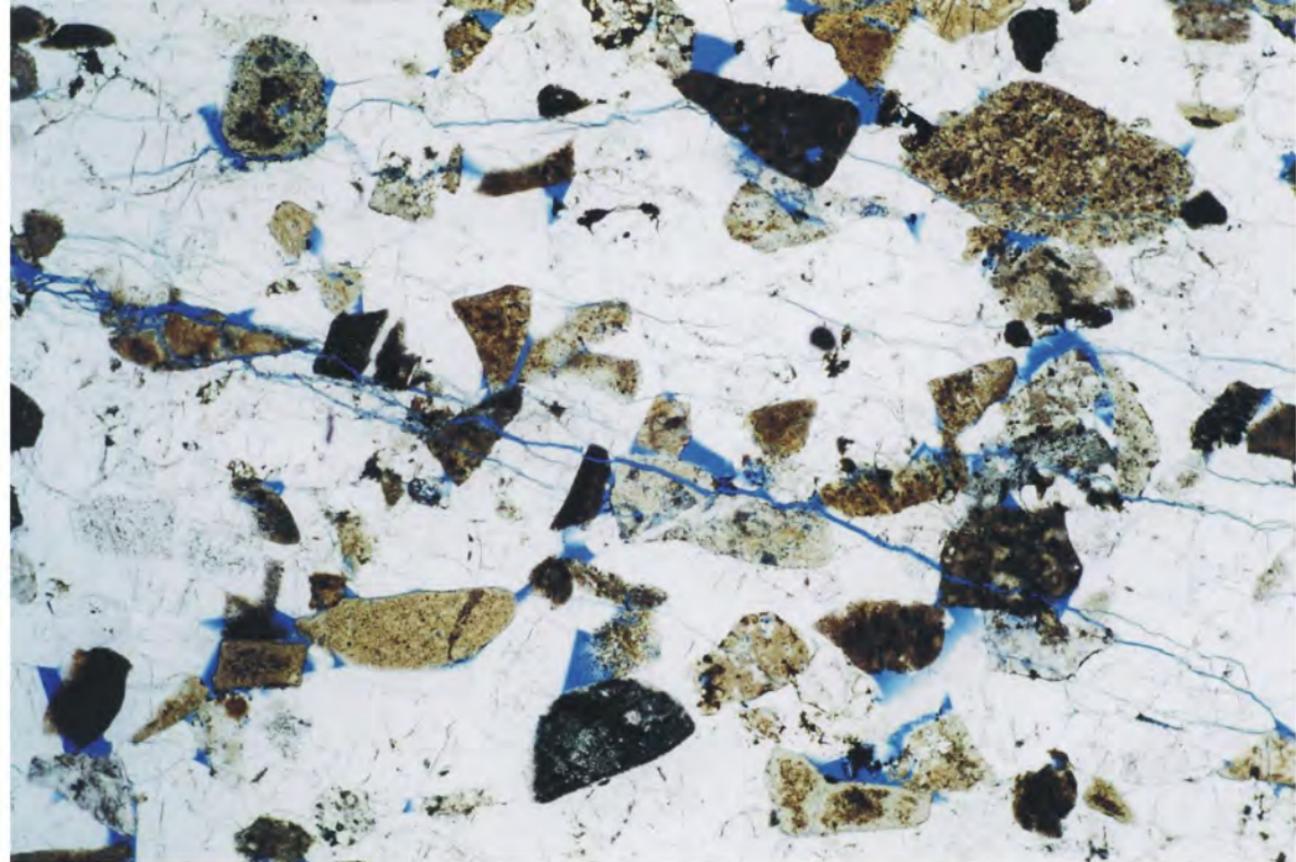
**Photo 3-9:** Cadomin Formation -- Poorly-sorted chert litharenite conglomerate. Silica and kaolin cements have filled most intergranular porosity, although there is limited development of secondary solution porosity in some chert grains.

Canhunter Esso Steepbank d-68-K/93-P-1, 2604.3 metres.



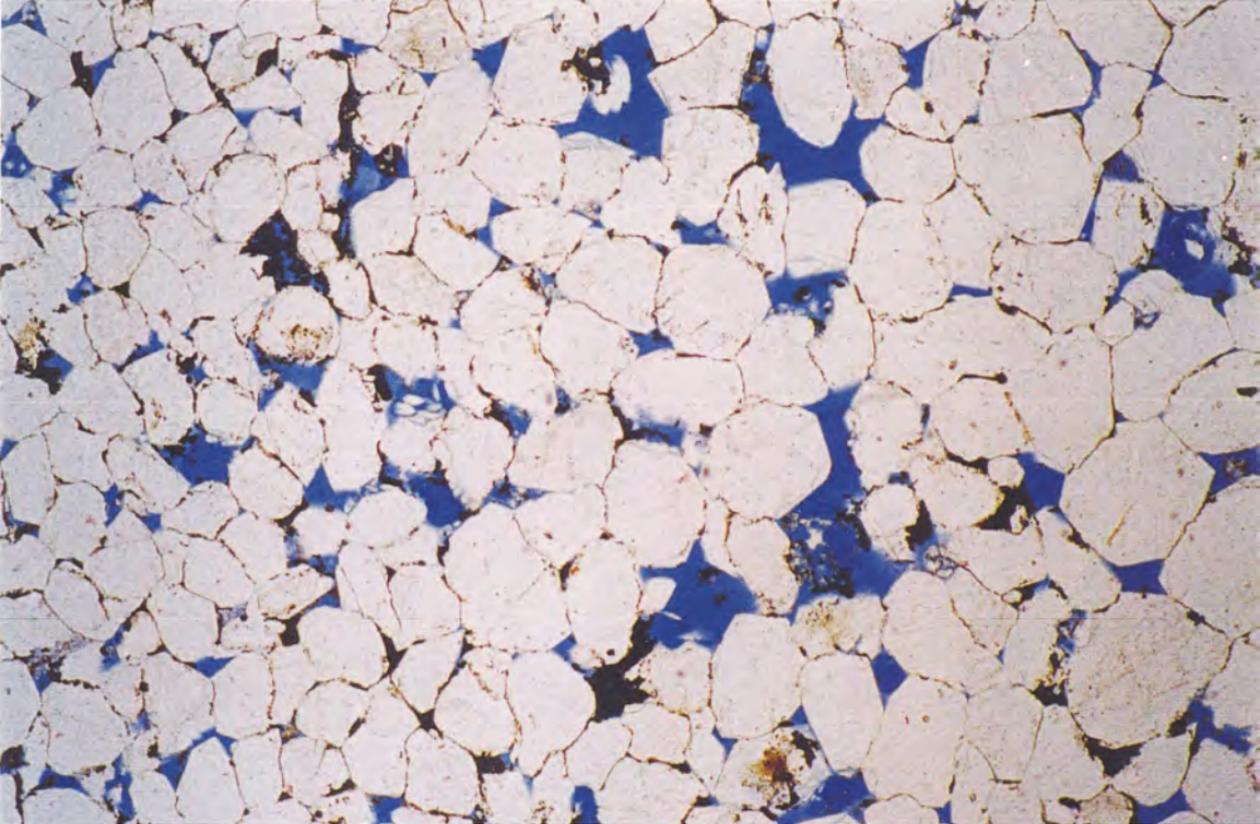
**Photo 3-10:** Nikanassin Formation -- Litharenite, extensively cemented by silica and minor ferroan dolomite. Essentially no remaining porosity.

Canhunter et al Cutbank a-23-H/93-P-8, 2231.5 metres.



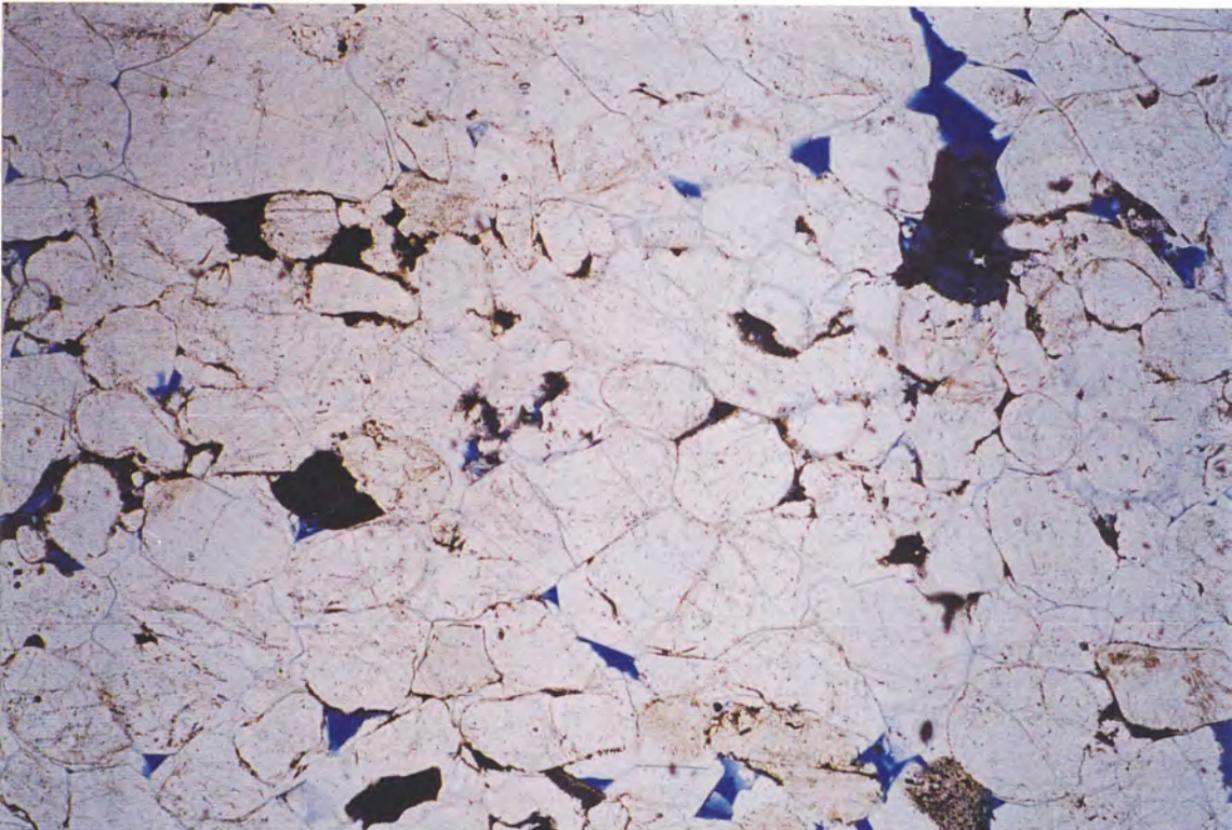
**Photo 3-11:** Nikanassin Formation -- Litharenite, as in Photo 3-10, but some primary intergranular porosity is preserved, and limited chert solution has taken place. Note presence of fractures.

a-23-H/93-P-8, 2247.4 metres



**Photo 3-12:** Buick Creek sandstone -- Quartzarenite, grading from coarse-grained (right) to fine-grained (left). Rock is well cemented by quartz overgrowths, but substantial primary porosity remains, along with minor secondary solution porosity of original lithic grains.

Dunlevy et al Buick Creek c-16-B/94-A-14, 3641.0 feet



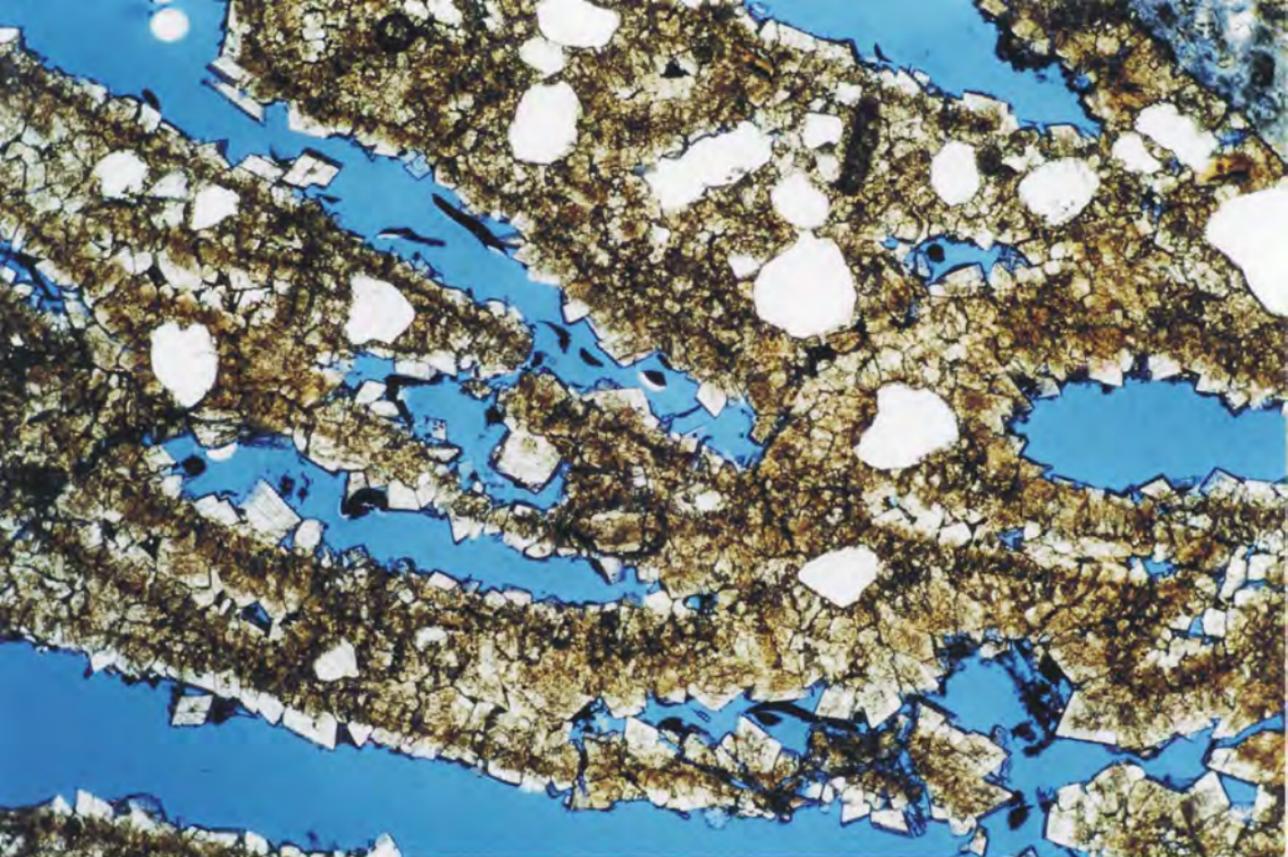
**Photo 3-13:** Buick Creek sandstone -- Quartzarenite, fine- to medium-grained, tightly cemented by quartz overgrowths. Remaining primary porosity consists of small, isolated pores; patchy bitumen fills some of the porosity.

Coseka et al Gundy a-8-H/94-B-16, 4442.0 feet



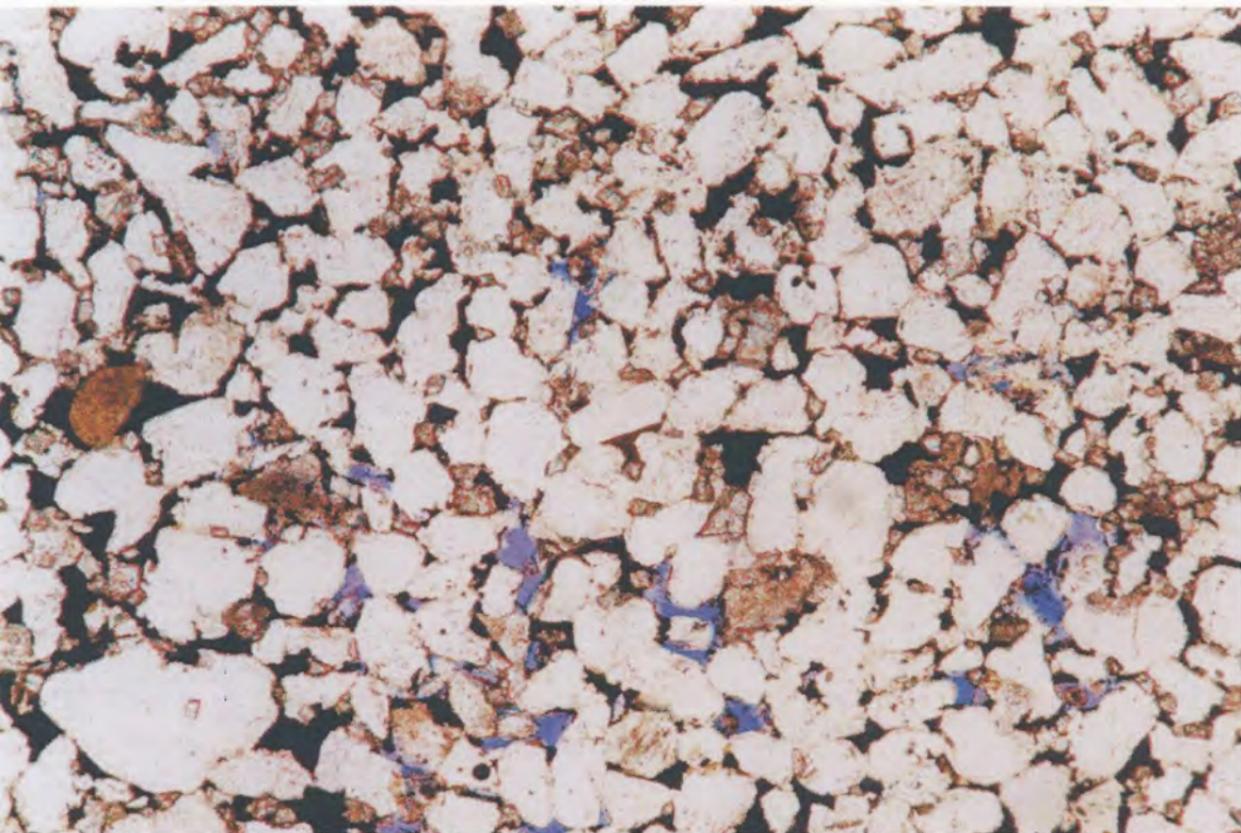
**Photo 3-14:** Halfway Formation -- Quartzarenite, moderately-sorted and fine-grained. Quartz overgrowths have modified primary porosity, but chert and calcite solution have generated some secondary porosity.

AEC Tupper d-99-1/93-P-8, 2589.1 metres.



**Photo 3-15:** Halfway Formation -- Sandy bioclastic dolomite, exhibiting original depositional texture of shelly packstone-grainstone.

PEX Norcen Horn d-55-A/94-G-9, 1370.2 metres



**Photo 3-16:** Mattson Formation -- Fine-grained quartzarenite; reservoir quality severely degraded by quartz overgrowths, carbonate cement, and pore-plugging bitumen. Remaining pores are poorly connected.

ARCO Maxhamish b-21-K/94-O-14, 5376.5 feet



APPENDIX 4

**Petrographic Table**

(select to view petrographic table)

Exploration Assessment of Tight Gas Plays, Northeastern British Columbia  
**PETROGRAPHIC SUMMARY**

Well	Depth (m)	Formation	TEXTURE					FRAMEWORK GRAINS											CEMENTS								Rock Type	Vis.Porosity(%)	Res.Quality	Comments	
			Grain Size Avg.	Grain Size Range	Sorting	Roundness	Compaction	Mono.Qtz	Poly.Qtz	Chert	Feldspar	SRF	MRF	Mica	Glaucinite	Phosphate	Detrital Carbonate	Heavy Minerals	Matrix Clays	Quartz	Kaolinite	Calcite	Dolomite	Fe-Dolomite	Chlorite	Pyrite					Bitumen
a-3-B / 93-P-1	938.7	Cardium	FU	VFU-ML	M	SA-SR	High	48	1	16	1	9	3	tr	tr	-	-	-	2	16	-	-	-	-	tr	-	3	LR	3.5	P	Poor visible porosity dominated by grain dissolution (chert, fspar, RF) and some modified primary intergr porosity; poorly interconnected pores; reserv quality reduced by high compaction and abundant qtz overgrowths.
a-85-A / 94-G-15	781.5	Sikanni	VFL	MSLT-FL	W	A-SA	Mod high	56	1	12	1	5	tr	-	tr	-	-	tr	22	1	-	-	-	-	-	1	-	LR	2	P	Poorly interconnected, small, grain-moldic pores (diss chert, fspar); trace modified primary intergr porosity; reserv quality reduced by fine gr size and clays.
b-24-A / 93-P-7	2054.3	Cadotte	Gran	ML-Gran	P	SA-R	Mod	3	tr	87	-	-	tr	tr	-	-	-	-	1	5	3	-	tr	-	tr	-	-	LR	15	G	Chert granule congl; good visible porosity consisting of mainly large modified primary intergr pores between chert clasts; pores commonly lined w drusy qtz.
c-14-F / 94-P-7	1850.5	Cadotte	MU	FU-CL	M	SA-R	High	32	3	40	-	9	1	-	-	-	-	-	tr	11	3	-	-	-	tr	tr	tr	LR	4	P	Poor visible porosity consisting of modified primary intergr plus some secondary grain diss (chert, RF); possible hairline fractures may provide some interconnectivity of pores.
c-14-F / 94-P-7	1853.8	Cadotte	Gran	FL-Peb	P	SA-R	High	9	1	81	-	tr	-	-	-	-	-	-	1	4	3	-	-	-	-	tr	-	LR	3	P	Poor visible porosity consisting of modified primary intergr plus trace chert grain dissolution pores; porosity occluded mainly be qtz and kaolinite cement.
b-2-H / 93-P-1	2199.4	Falher	Gran	MU-Peb	P	SA-R	Mod	4	2	73	-	tr	-	-	-	-	-	-	-	17	-	-	-	-	-	-	3	LR	9	G	Chert granule congl; fair visible porosity consisting of mostly modified primary intergr pores; large pores between chert clasts, partly plugged by bitumen.
b-28-G / 93-P-1	2333.0	Falher	CU	FU-VCU	P	SA-SR	High	3	2	80	-	2	tr	-	-	-	-	-	tr	11	1	-	-	tr	-	tr	tr	LR	6	M	Fair visible porosity consisting of modified primary intergr and trace chert grain dissolution; reserv quality reduced by compaction and abundant qtz overgrowths.
b-28-G / 93-P-1	2334.7	Falher	FU/Peb	VFU-Peb	P	SA-R	High	3	-	91	tr	tr	tr	-	-	-	-	-	tr	5	tr	-	-	-	tr	-	tr	LR	3	P	Chert pebble congl with sand matrix; poor visible porosity consisting of modified primary and some diss of grains (chert, RF, fspar); pores mainly in matrix sand.
b-28-G / 93-P-1	2343.5	Falher	FU	VFL-VCU	P	SA-SR	High	35	1	25	1	7	2	-	tr	-	4	-	tr	17	-	-	-	7	-	tr	-	LR	4	P	Small pores poorly interconnected; modified primary intergr and secondary grain diss pores (chert, RF, fspar); reserv quality reduced by fine grain size, high compaction, and qtz overgrowths.
d-73-D / 93-P-8	2382.0	Bluesky	FU	VFU-MU	M	SA-SR	High	28	1	42	3	3	tr	-	-	-	-	-	tr	24	1	-	-	-	tr	tr	tr	LR	1	P	Poor visible porosity; poorly interconnected modified primary intergr pores; reserv quality reduced by high compaction and abundant qtz overgrowths.
b-18-E / 93-P-8	2397.5	Bluesky	ML	VFU-CL	P	SA-SR	High	15	3	22	-	12	3	-	-	-	6	-	tr	-	-	-	-	38	-	tr	tr	LR	0	P	Tightly cemented with ferroan dolomite.
d-68-K / 93-P-1	2604.3	Cadomin	MU/Peb	FU-Peb	P	SA-R	Mod high	5	tr	86	-	tr	tr	tr	-	-	-	-	1	4	3	-	-	-	-	tr	-	LR	3.5	P	Chert pebble congl with sand matrix; poor visible porosity consisting of modified primary intergr and some secondary diss of chert clasts; main cements are quartz and kaolinite; pores commonly lined w drusy qtz.
a-23-H / 93-P-8	2231.5	Minnes (Niknsin)	MU	VFU-VCL	P	SA-R	High	30	1	40	-	8	-	-	-	-	-	tr	tr	16	-	-	-	2	-	-	2	LR	tr	P	Very poor visible porosity, poorly interconnected pores; rare chert grain diss; possible trace hairline fracture porosity.
a-23-H / 93-P-8	2236.8	Minnes (Niknsin)	MU	VFU-VCL	P	SA-R	High	30	1	33	-	13	tr	-	-	-	-	tr	3	14	-	-	-	4	-	-	1	LR	5	M	Fair visible porosity consisting of modified primary intergr and common grain dissolution (chert, RF); moderately interconnected small pores.
a-23-H / 93-P-8	2247.4	Minnes (Niknsin)	MU	FU-CU	M	SA-R	High	50	2	20	-	3	-	-	-	-	-	-	tr	24	-	-	-	-	-	-	tr	LR	6	M	Fair visible porosity consisting of modified primary intergr and some grain dissolution (chert, RF) plu possible hairline fracture porosity; moderate pore interconnectivity; abundant qtz overgrowths.
d-99-l / 93-P-8	2589.1	Halfway	FU	VFL-ML	M	SA-SR	Mod	70	1	3	tr	tr	-	-	-	-	tr	3	tr	13	-	7	-	2	-	tr	-	QA	12	G	Good visible porosity, somewhat patchy; pore types are modified primary intergr plus chert grain dissolution plus calcite cement dissolution.

Exploration Assessment of Tight Gas Plays, Northeastern British Columbia  
**PETROGRAPHIC SUMMARY**

Well	Depth (m)	Formation	TEXTURE					FRAMEWORK GRAINS											Matrix Clays	CEMENTS							Rock Type	Vis.Porosity(%)	Res.Quality	Comments	
			Grain Size Avg.	Grain Size Range	Sorting	Roundness	Compaction	Mono.Qtz	Poly.Qtz	Chert	Feldspar	SRF	MRF	Mica	Glauconite	Phosphate	Detrital Carbonate	Heavy Minerals		Quartz	Kaolinite	Calcite	Dolomite	Fe-Dolomite	Chlorite	Pyrite					Bitumen
d-99-1 / 93-P-8	2598.0	Halfway	FU/MU	VFL-CL	P	SA-R	Mod	62	tr	tr	tr	-	-	-	-	tr	2	tr	-	11	-	24	tr	-	-	tr	-	QA	2	P	Poor visible porosity consisting of modified primary intergr and some secondary chert grain diss; possible trace calcite cement dissolution; reservoir quality reduced by abundant calcite cement.
d-55-A / 94-G-9	1360.1	Halfway	ML	VFU-CL	P	SA-R	Mod high	63	tr	18	tr	tr	-	-	-	tr	tr	tr	-	13	-	tr	3	-	-	tr	2	SL	13	G	Good visible porosity consisting of mostly secondary chert grain dissolution.
d-55-A / 94-G-9	1370.2	Halfway	ML	VFL-CL	P	SA-SR		7	-	-	-	-	-	-	-	1	-	-	-	tr	-	-	91	-	-	-	tr	dol	13	G	Sandy dolomite with original depositional texture of shelly packstone-grainstone (coquina); qtz + phosph detrital grains; trace qtz and chert cement; good moldic/vuggy porosity.



APPENDIX 5

**Applecore™ Core Descriptions**

(select to view individual core data)

# Core Logs

- Core Log #1
- Core Log #2
- Core Log #3
- Core Log #4
- Core Log #5
- Core Log #6
- Core Log #7
- Core Log #8
- Core Log #9
- Core Log #10
- Core Log #11
- Core Log #12
- Core Log #13
- Core Log #14
- Core Log #15
- Core Log #16
- Core Log #17



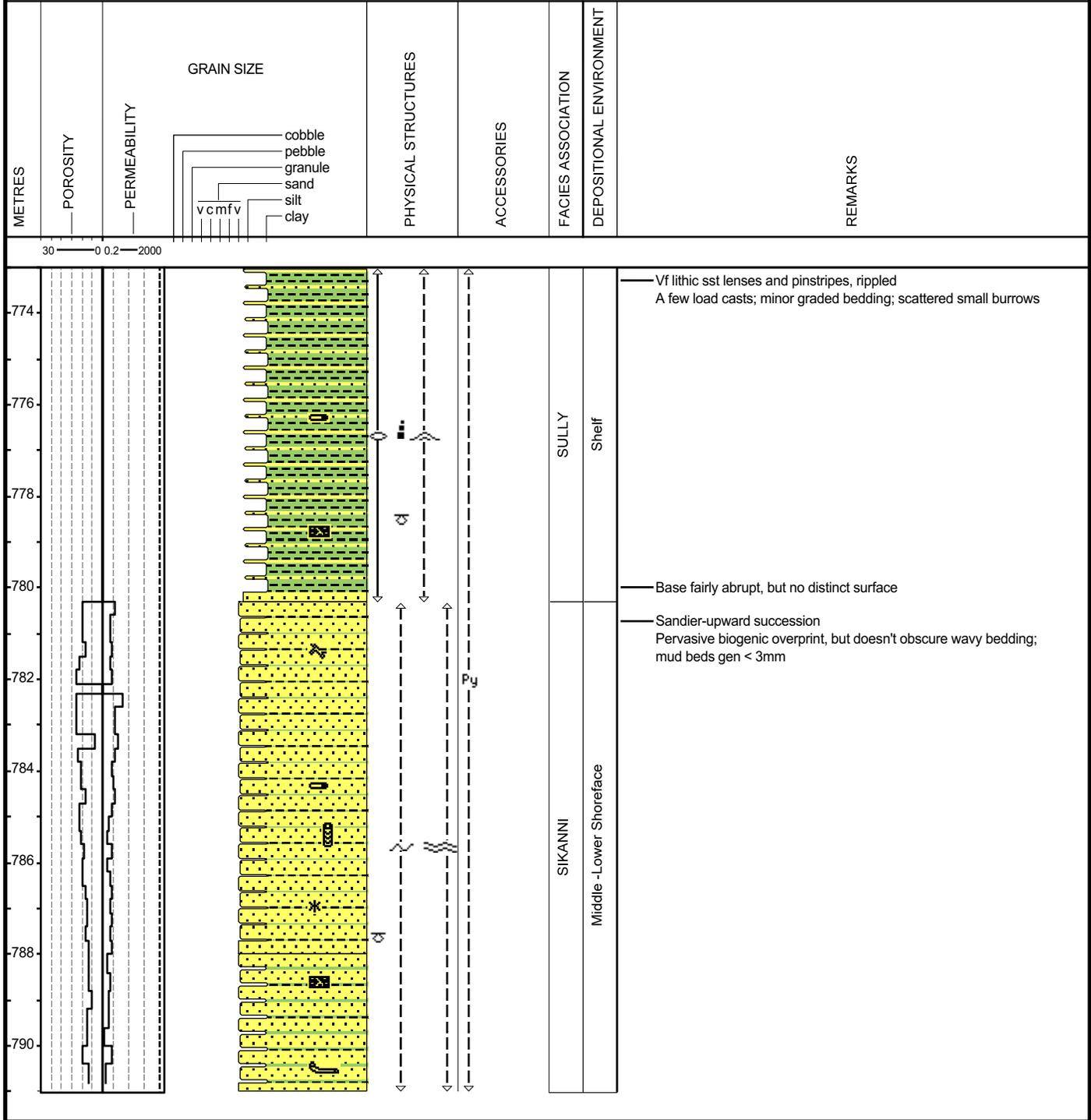
**Suncor Bougie**  
a-85-A / 94-G-15

Remarks: SIKANNI FORMATION

Core #1: 773 - 791.2 (Rec. 18.2 m)

**CORE LOG #2**

3.5" core, slabbed



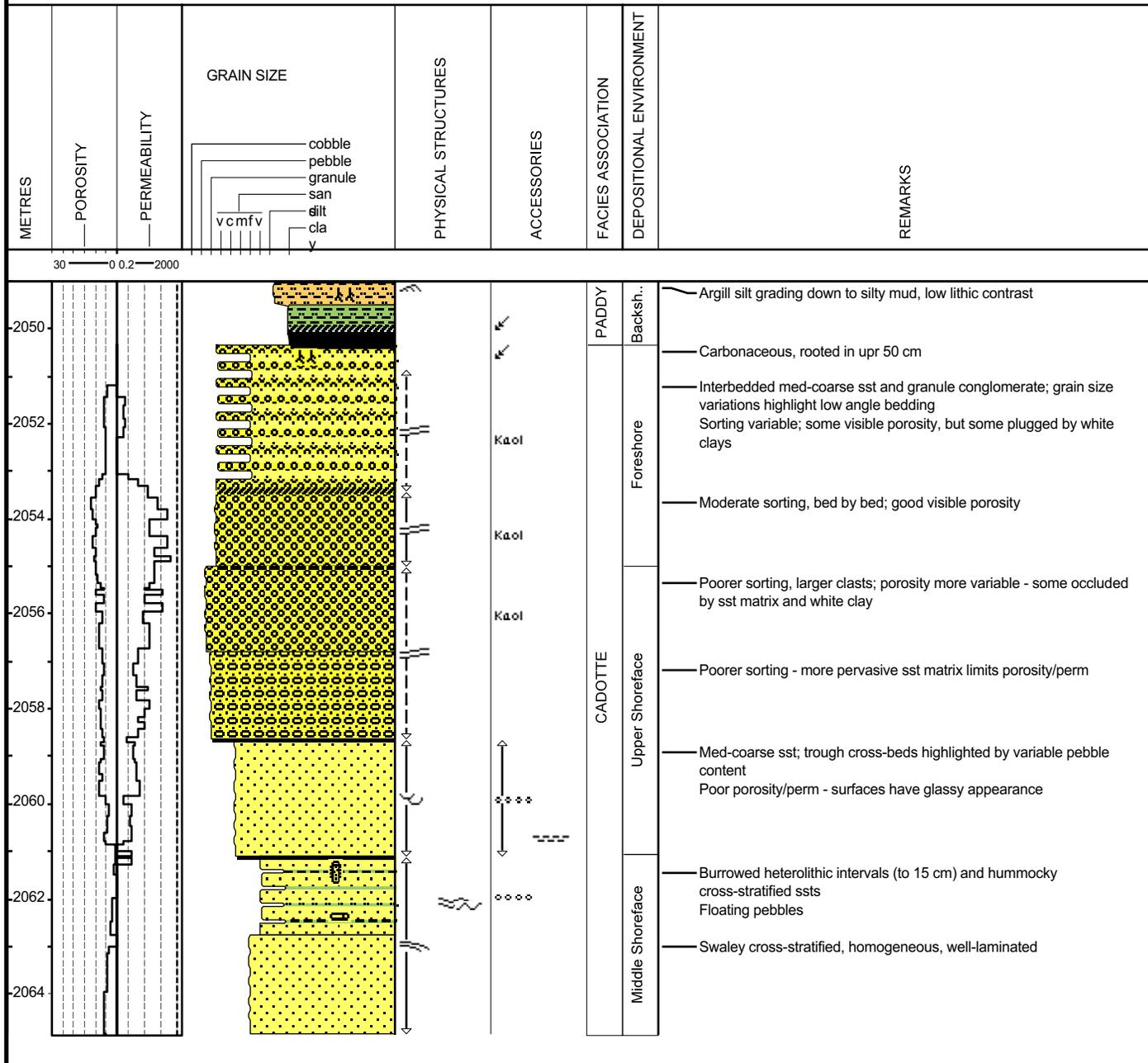
**CanHunter Noel**  
b-24-A / 93-P-7

Remarks: CADOTTE MEMBER  
Conglomeratic Shoreface  
(High-quality reservoir)

**CORE LOG #3**

Core #1: 2049 - 2067 (Rec. 15.85 m)

4" core, slabbed



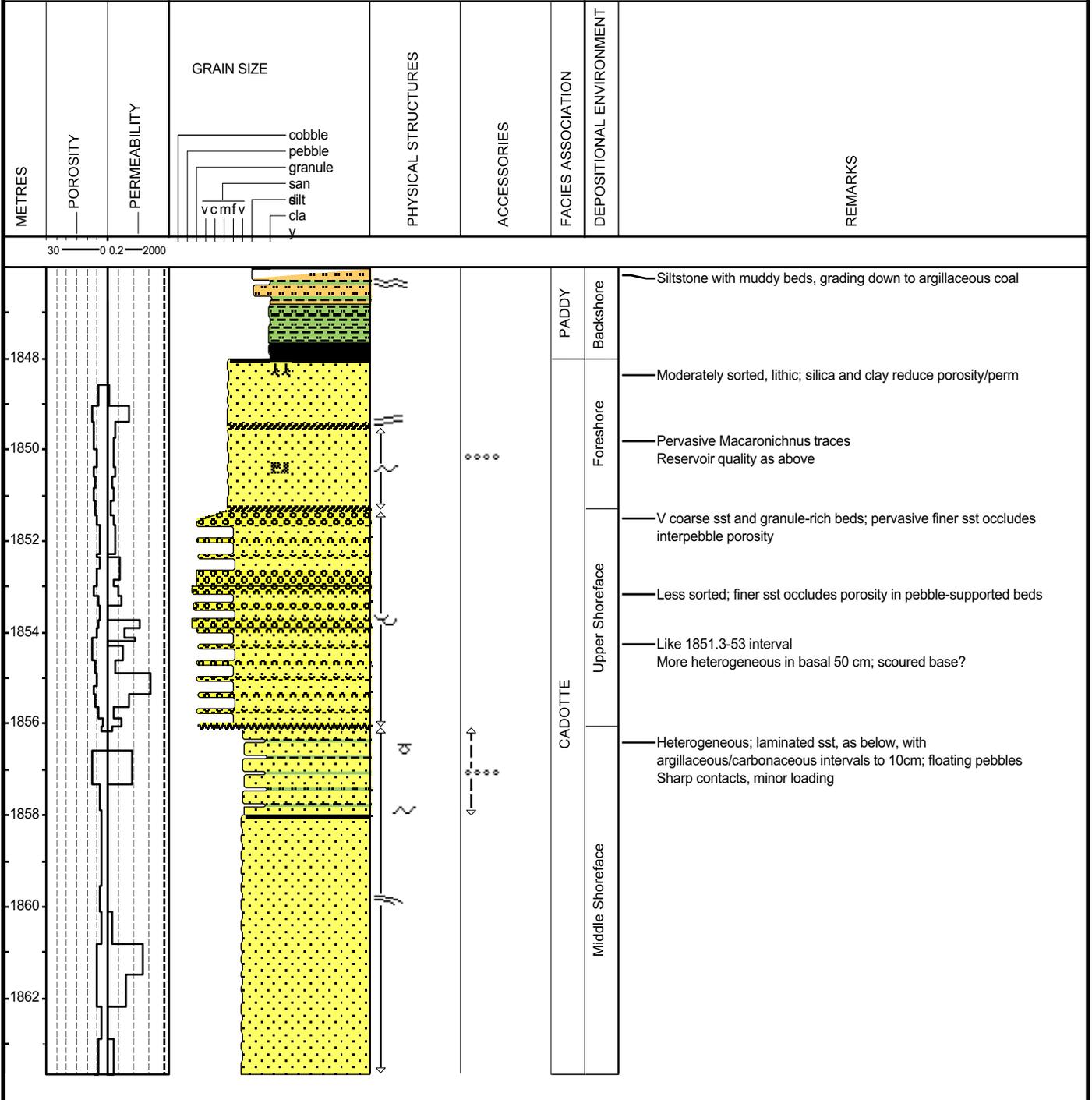
**CanHunter et al Jackpine**  
c-14-F / 93-P-7

Remarks: CADOTTE MEMBER  
Sandy Shoreface  
(Poor reservoir quality)

**CORE LOG #4**

Core #1: 1846 - 1864 (Rec. 17.66 m)

4" core, slabbed



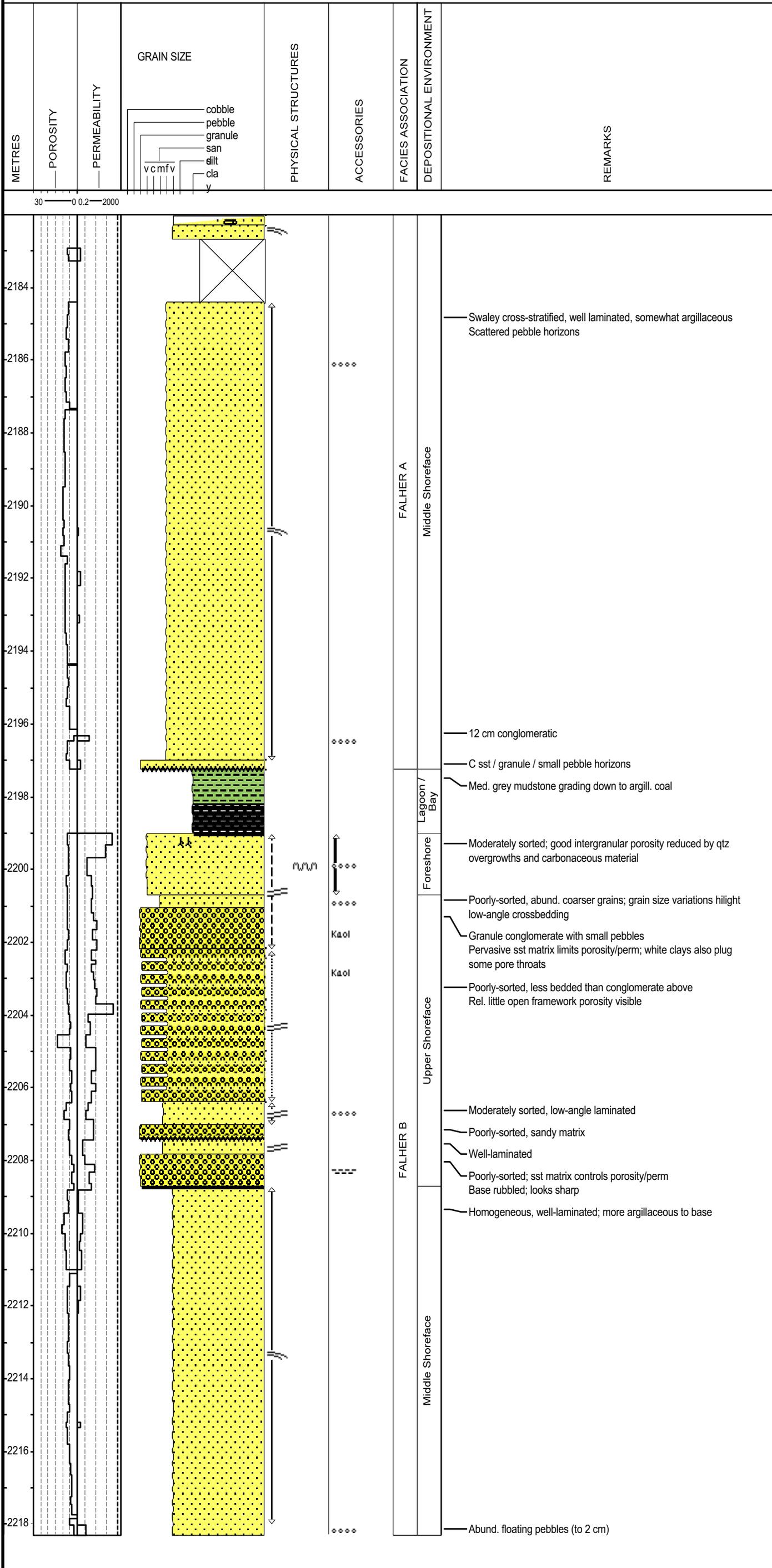
Esso Windsor  
b-2-H / 93-P-1

Remarks: SPIRIT RIVER FM / FALHER MEMBER  
Conglomeratic Shoreface  
(High-quality reservoir)

Core #1: 2182.7 - 2183.8 (Rec. 0.6 m)  
Core #2: 2184.4 - 2202.6 (Rec. 18.2 m)  
Core #3: 2202.6 - 2220.8 (Rec. 18.2 m)

CORE LOG #5

4" core, slabbed



# CanHunter Union Kelly

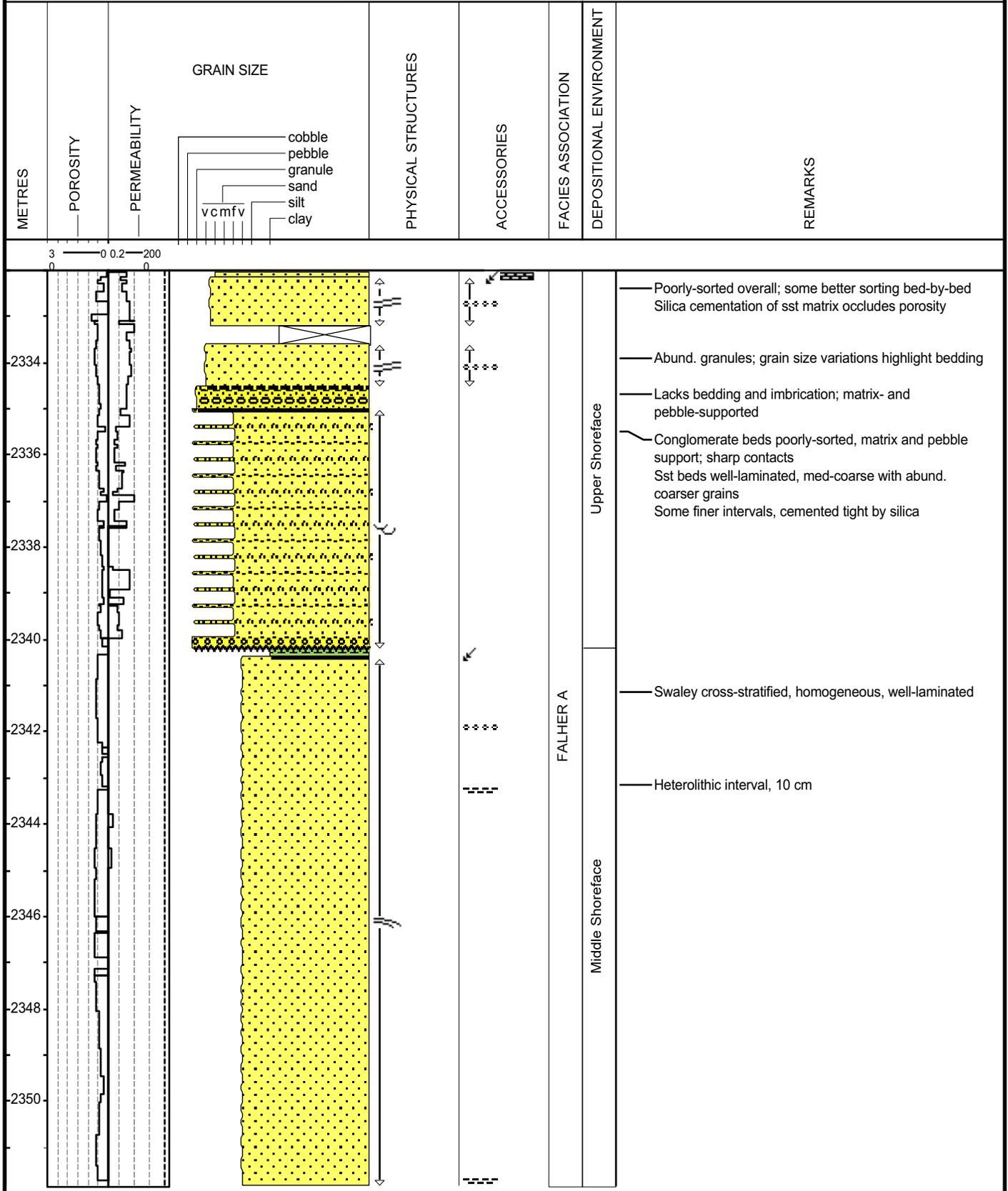
b-28-G / 93-P-1

Remarks: SPIRIT RIVER FM / FALHER MEMBER  
Sandy Shoreface  
(Poor-quality reservoir)

## CORE LOG #6

Core #1: 2332 - 2338.25 (Rec. 6.5)  
Core #2: 2338.25 - 2352 (Rec. 13.57)

4" core, slabbed





Remarks: BLUESKY FORMATION  
Basal Unit

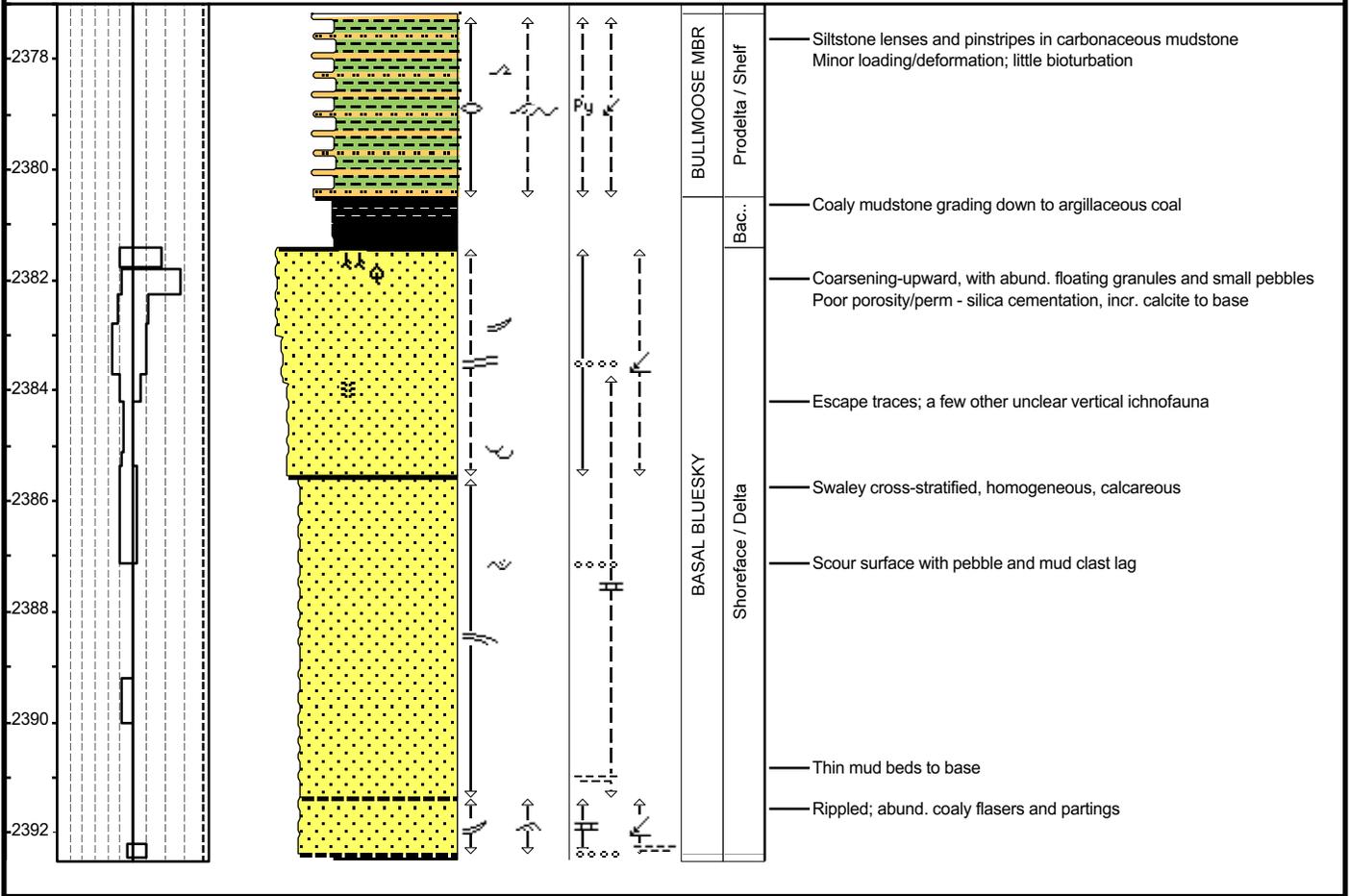
Core #1: 2377.2 - 2381.8 (Rec. 4.55 m)  
Core #2: 2381.8 - 2393 (Rec. 10.7 m)

CORE LOG #8

4" core, unslabbed, fairly clean

METRES	POROSITY	PERMEABILITY	GRAIN SIZE	PHYSICAL STRUCTURES	ACCESSORIES	FACIES ASSOCIATION	DEPOSITIONAL ENVIRONMENT	REMARKS
			cobble pebble granule sand silt clay					

30 0.02 200



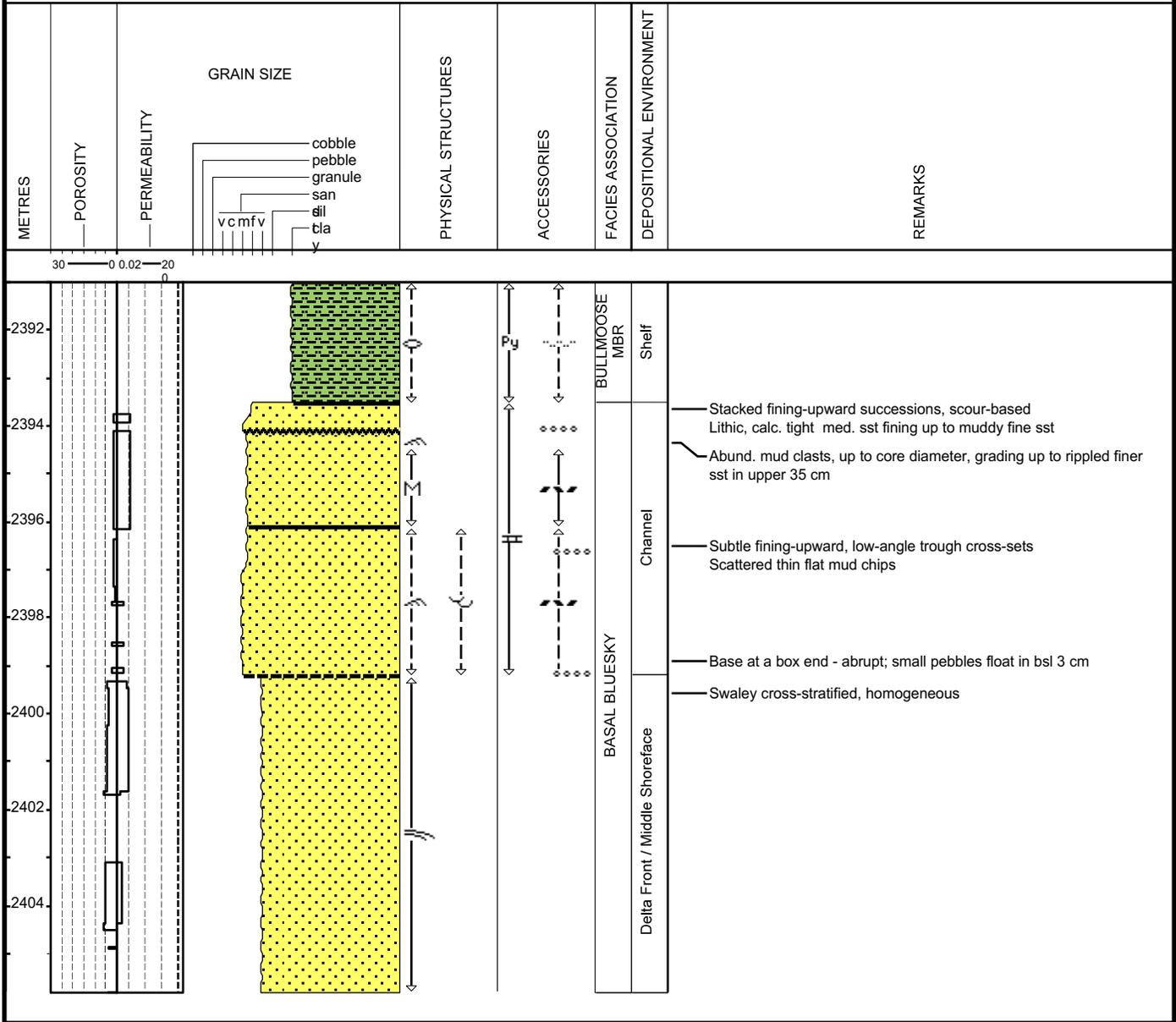
CanHunter et al Noel  
b-18-E / 93-P-8

Remarks: BLUESKY FORMATION  
Basal Unit

Core #3: 2388 - 2406.2 (Rec. 17.8 m)

CORE LOG #9

4" core, slabbed

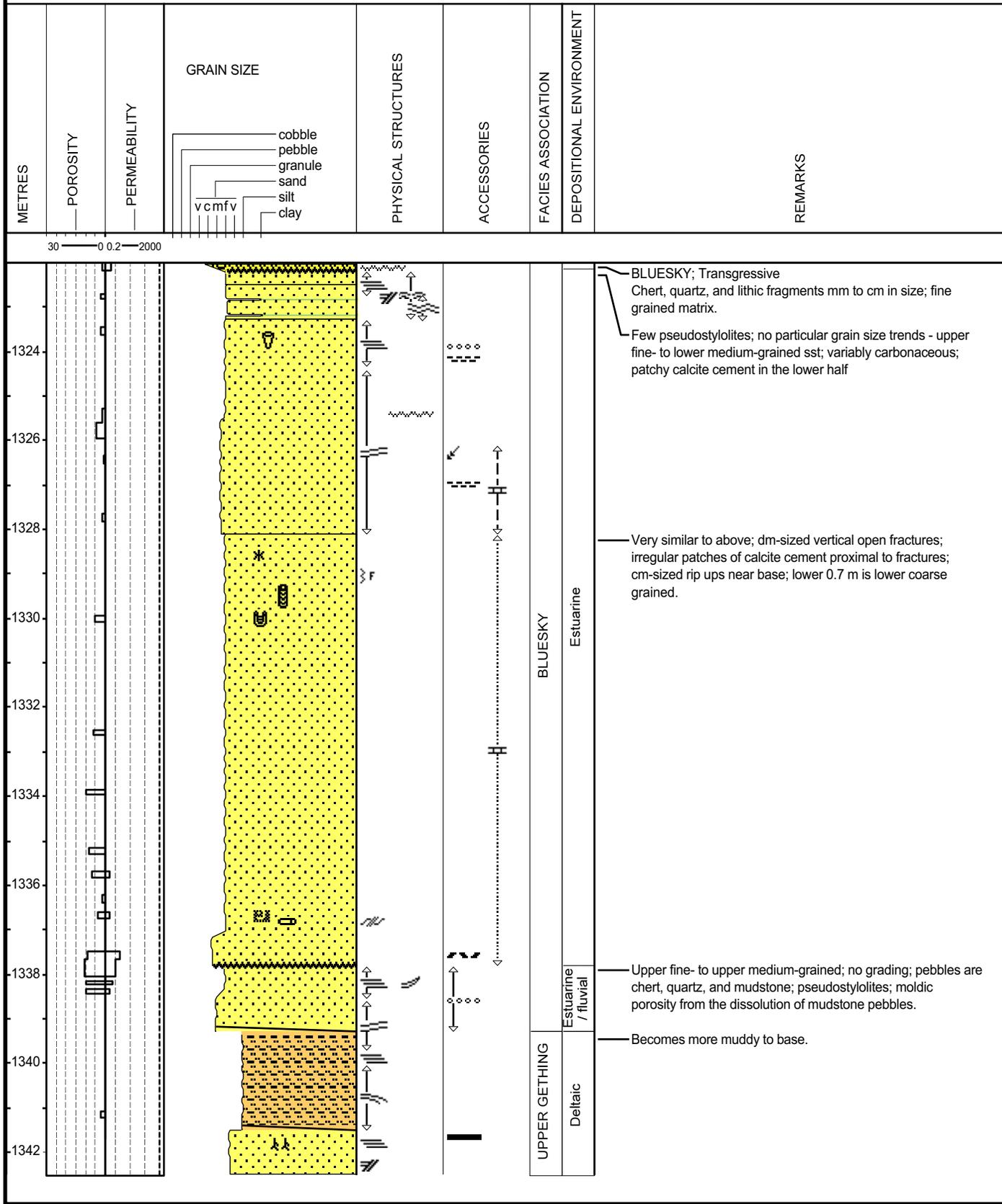


**CanHunter Town**  
c-89-G / 94-B-16

Remarks: BLUESKY FORMATION  
Buick Creek Valley Fill

**CORE LOG #10**

Core #1: 1322 - 1328.5 (Rec. 6.3 m)  
Core #2: 1328.5 - 1342 (Rec. 13.2 m)

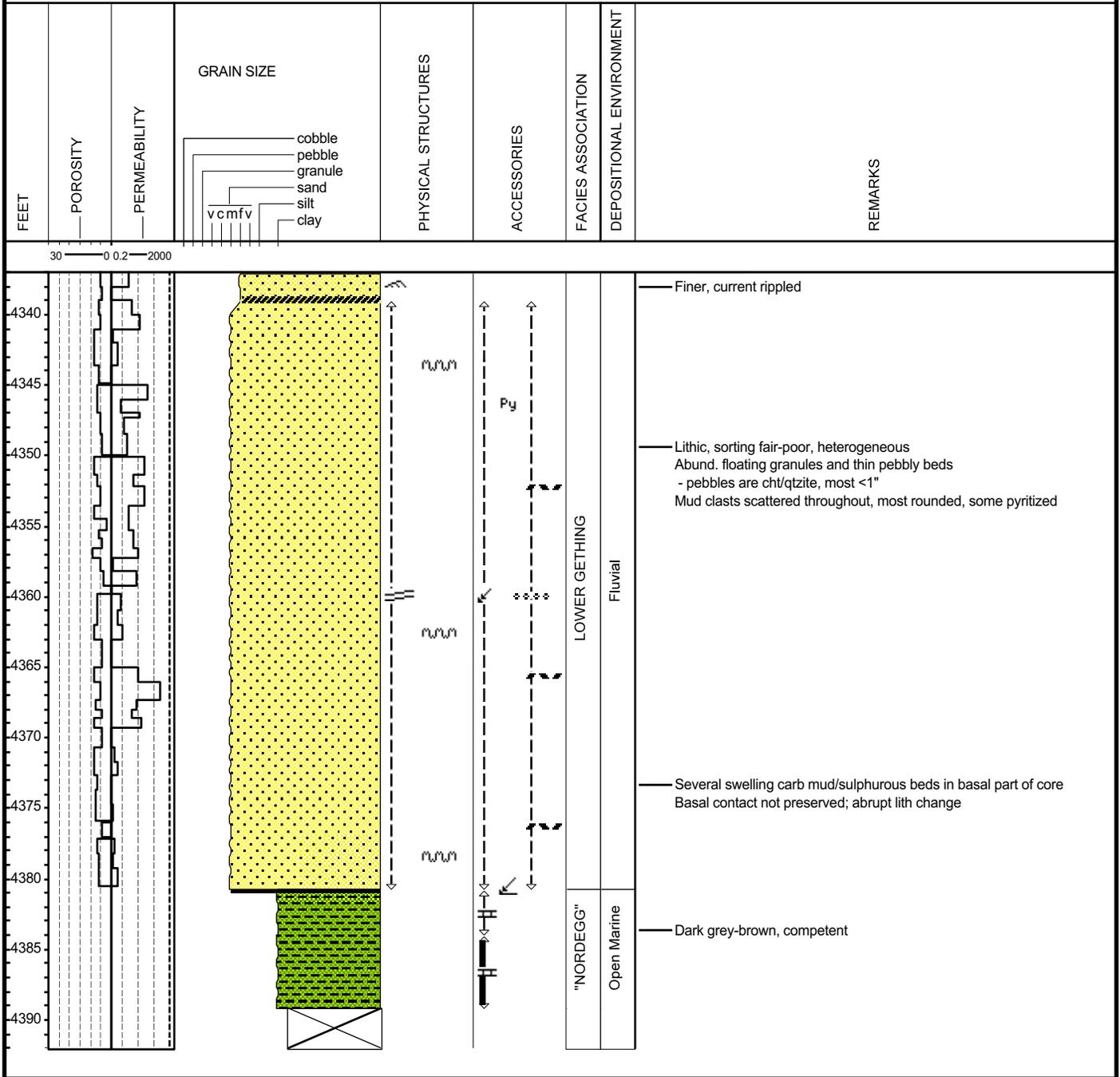


Remarks: LOWER GETHING FORMATION  
Buick Creek - Laprise Valley Fill

CORE LOG #11

Core #1: 4337-4392 (Rec 54')

3.5" core - unslabbed



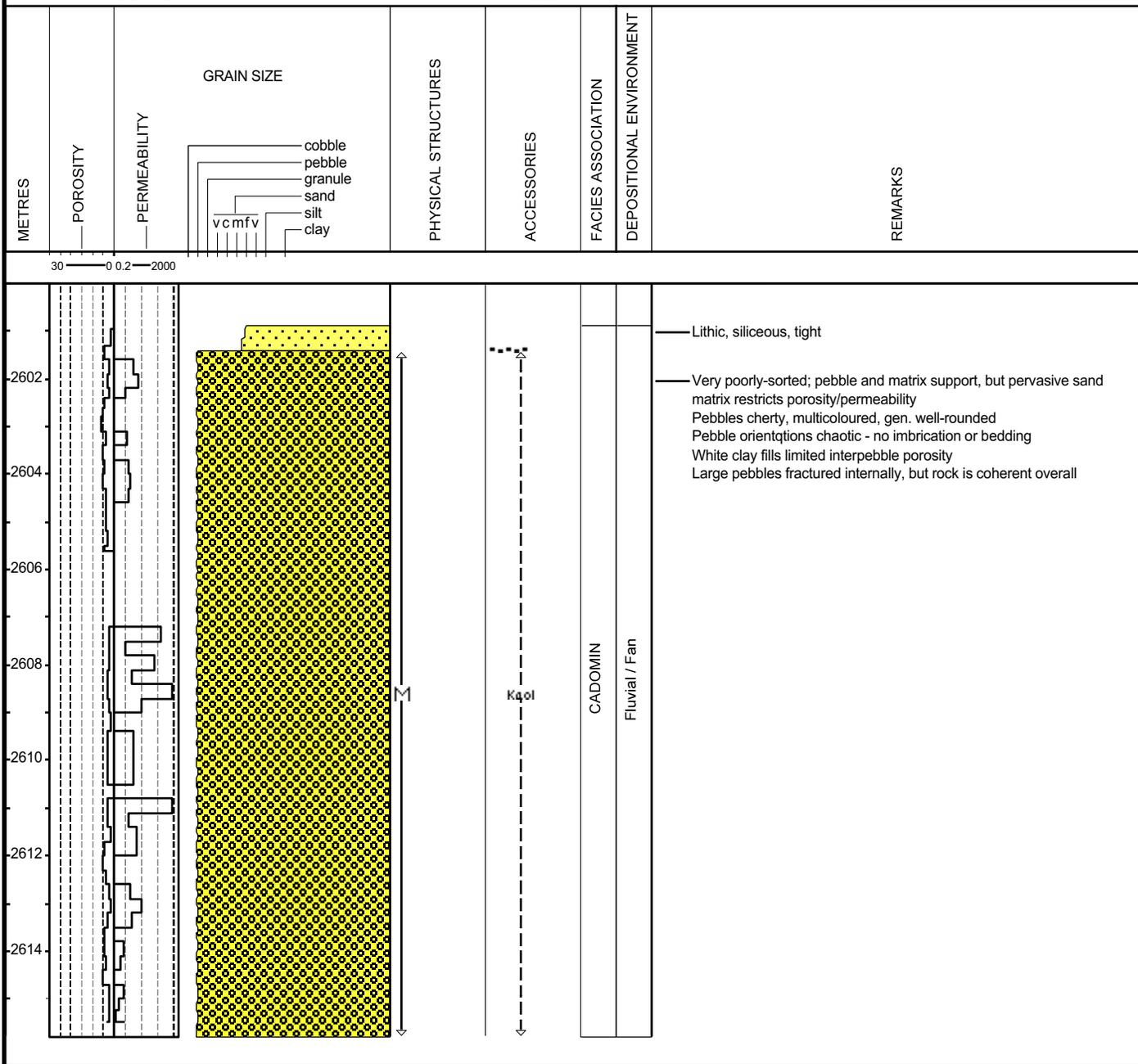
**CanHunter Esso Steeprock**  
d-68-K / 93-P-1

Remarks: CADOMIN FORMATION

Core #7: 2596 - 2606.8 (Rec. 9.6 m)  
 Core #8: No Recovery  
 Core #9: 2606.9 - 2610.5 (Rec. 2.7 m)  
 Core #10: 2610.5 - 2617.4 (Rec. 5.3 m)

**CORE LOG #12**

4" core, slabbed  
 Upper, post-Cadomin siltstone and mudstone not logged



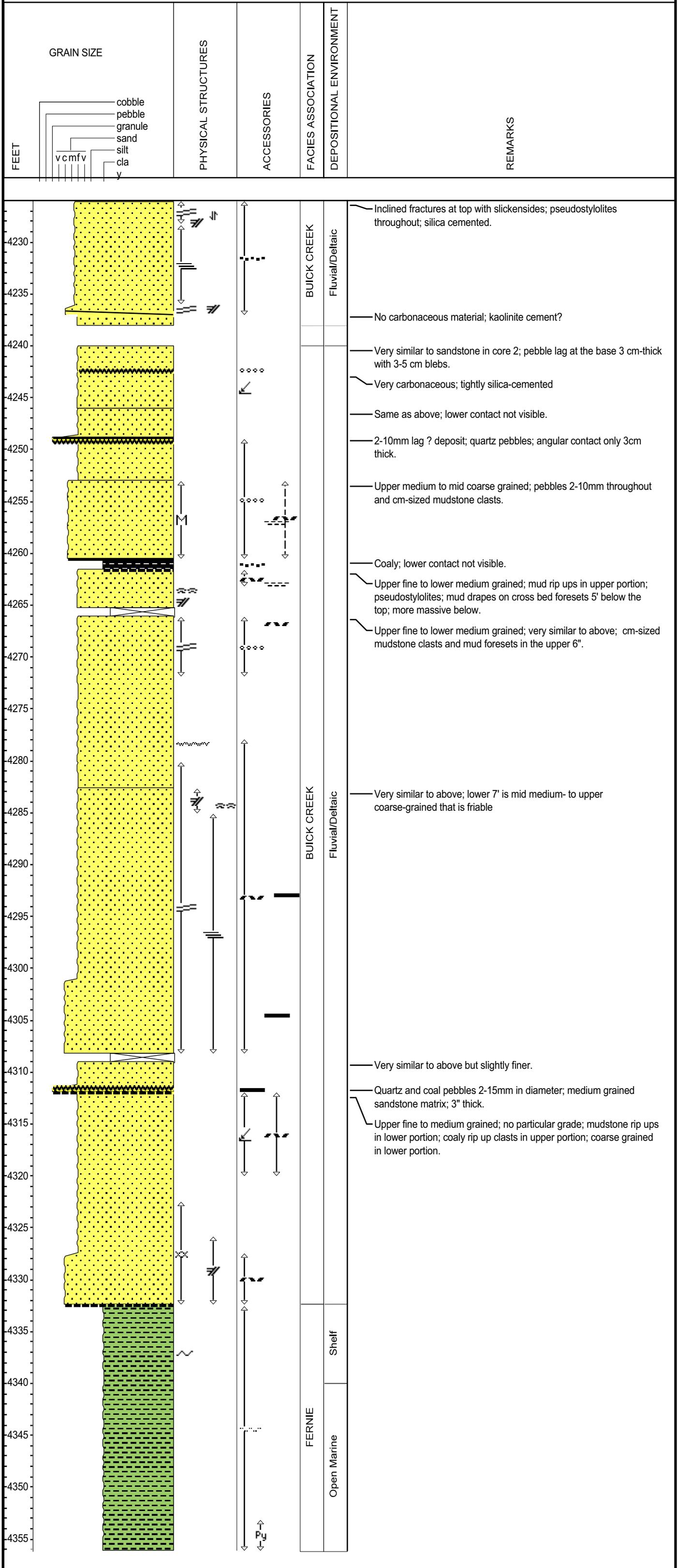


**Suncor et al Blueberry**  
c-32-D / 94-A-13

Remarks: BUICK CREEK FORMATION  
(Minnes Group)

Core #2: 4226 - 4238 (Rec. 12')  
Core #3: 4240 - 4246 (Rec. 6')  
Core #4: 4246 - 4266 (Rec. 20')  
Core #5: 4266 - 4284 (Rec. 17')  
Core #6: 4284 - 4309 (Rec. 25')  
Core #7: 4309 - 4356 (Rec. 45')  
No core analysis

**CORE LOG #14**



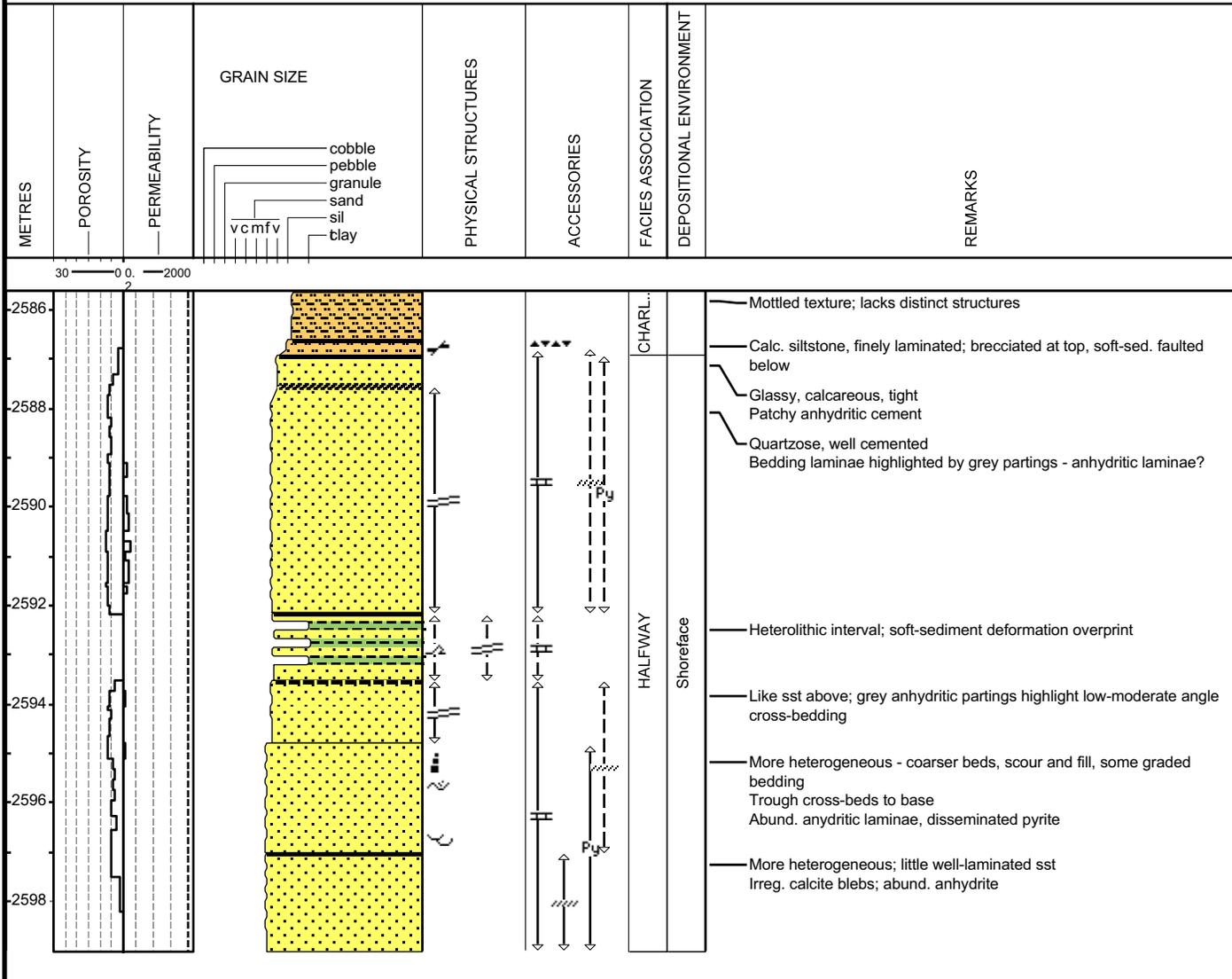
Remarks: HALFWAY FORMATION

Core #1: 2585.6 - 2592.9 (Rec. 7.05 m)

Core #2: 2592.9 - 2599.6 (Rec. 6.1 m)

CORE LOG #15

4" core, slabbed



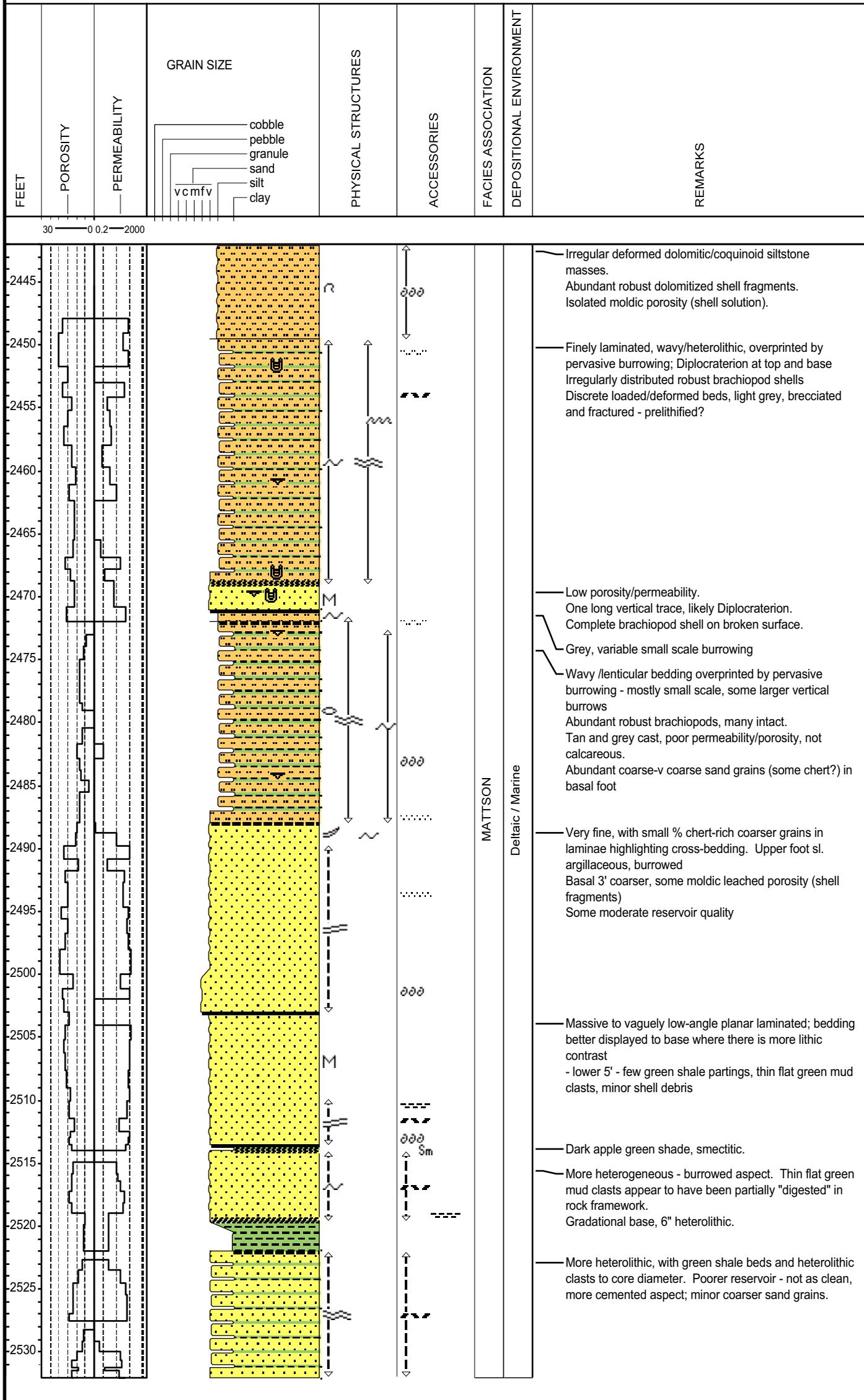
**Aquitaine et al Tattoo**  
a-78-L / 94-O-10

Remarks: MATTSON FORMATION

Core #1: 2442-2472' (Rec. 30')  
Core #2: 2472-2532' (Rec. 60')

**CORE LOG #16**

3.5" core, slabbed



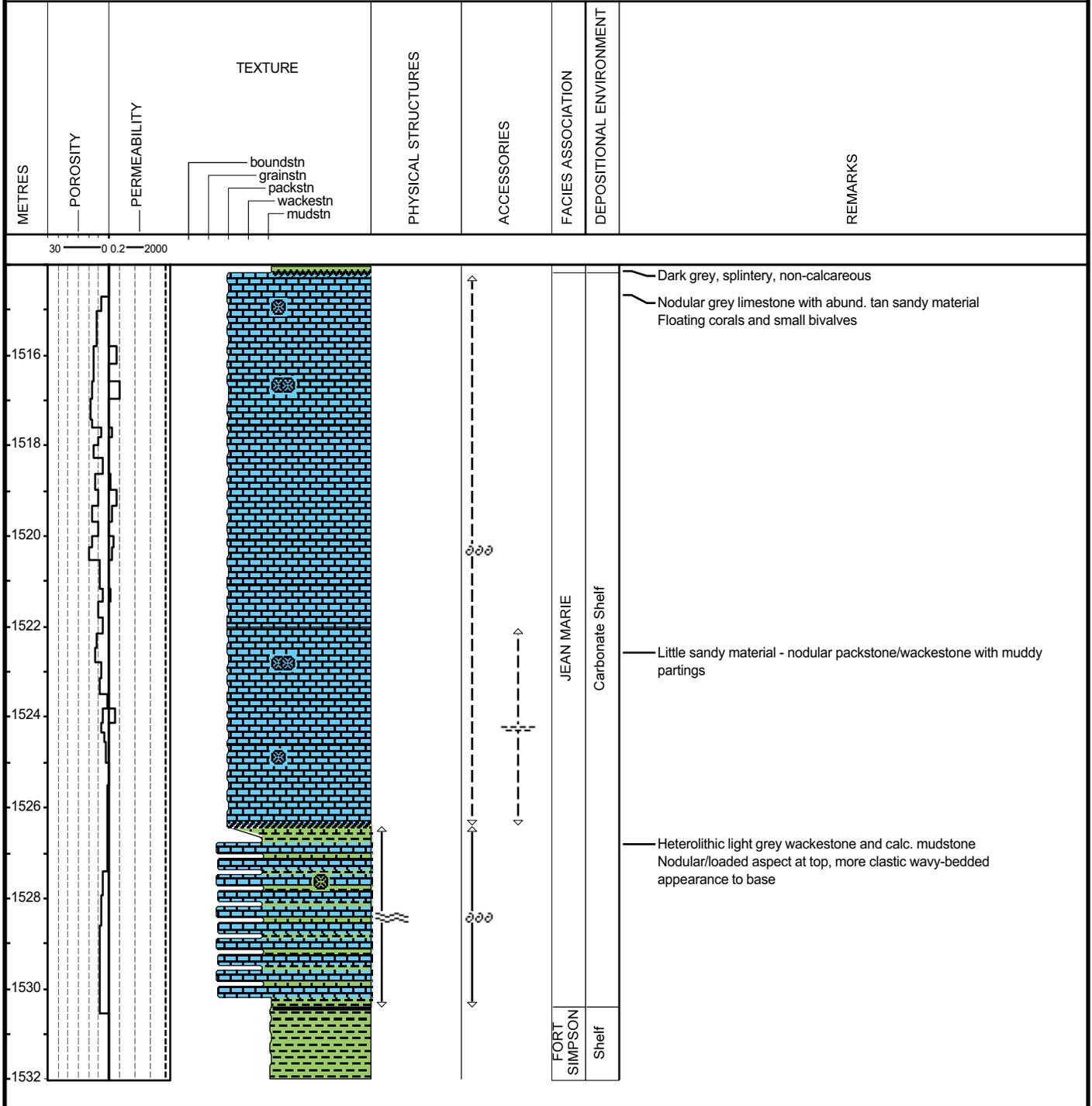
**Scurry Westcoast Ring**  
c-12-E / 94-I-1

Remarks: JEAN MARIE MEMBER

Core #3: 1514 - 1532 (Rec. 18.0 m)

**CORE LOG #17**

4" core, slabbed

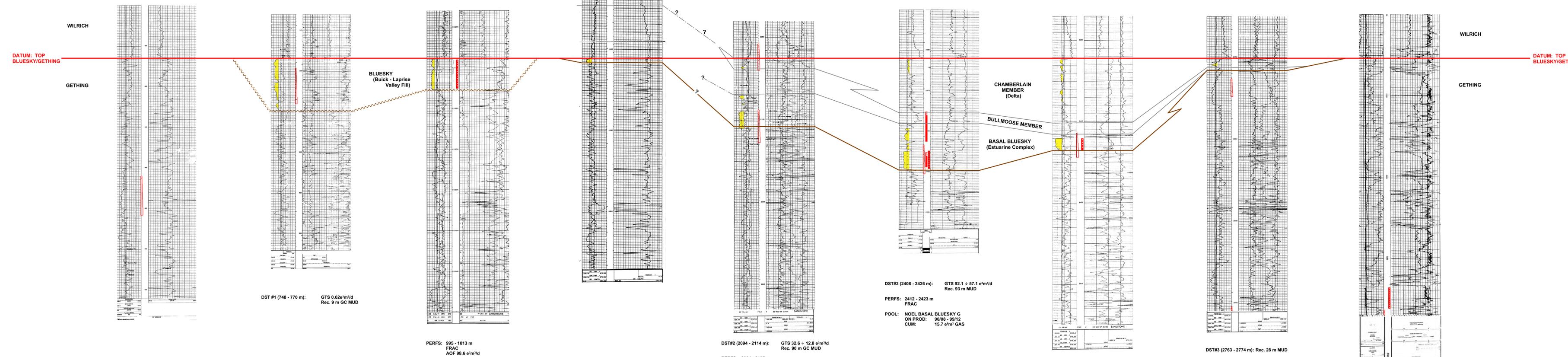
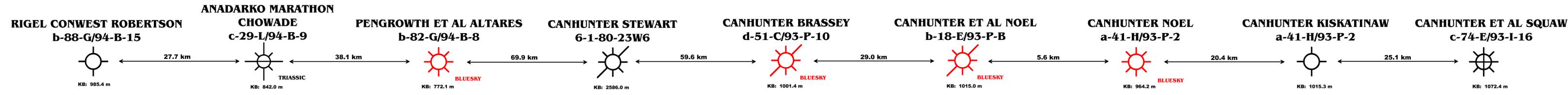


# STRATIGRAPHIC CROSS-SECTIONS

- Cadomin
- Cardium
- Dunvegan
- Spirit River
- Bluesky
- Cadotte
- Nikanassin
- Mattson
- Halfway

- Select Cross-Section from Map





DST #1 (748 - 770 m): GTS 0.62e<sup>3</sup>m<sup>3</sup>/d  
Rec. 9 m GC MUD

PERFS: 995 - 1013 m  
FRAC  
AOF 98.6 e<sup>3</sup>m<sup>3</sup>/d  
POOL: ALTARES BLUESKY B  
ON PROD: 90/11  
CUM: 174 e<sup>3</sup>m<sup>3</sup> GAS

DST#2 (2094 - 2114 m): GTS 32.6 ± 12.8 e<sup>3</sup>m<sup>3</sup>/d  
Rec. 90 m GC MUD

PERFS: 2094 - 2105 m  
ACID + FRAC  
POOL: BRASSEY BASAL BLUESKY A  
ON PROD: 91/10  
CUM: 7.90 e<sup>3</sup>m<sup>3</sup> GAS

DST#2 (2408 - 2426 m): GTS 92.1 ± 57.1 e<sup>3</sup>m<sup>3</sup>/d  
Rec. 93 m MUD

PERFS: 2412 - 2423 m  
FRAC  
POOL: NOEL BASAL BLUESKY G  
ON PROD: 90/08 - 99/12  
CUM: 15.7 e<sup>3</sup>m<sup>3</sup> GAS

DST#3 (2407 - 2422 m): GTS 414 ± 302 e<sup>3</sup>m<sup>3</sup>/d  
Rec. 1 m MUD

PERFS: 2410.5 - 2417.5 m  
FRAC  
AOF 386 e<sup>3</sup>m<sup>3</sup>/d  
POOL: NOEL BASAL BLUESKY B  
ON PROD: 88/07  
CUM: 262 e<sup>3</sup>m<sup>3</sup> GAS

DST#3 (2763 - 2774 m): Rec. 28 m MUD

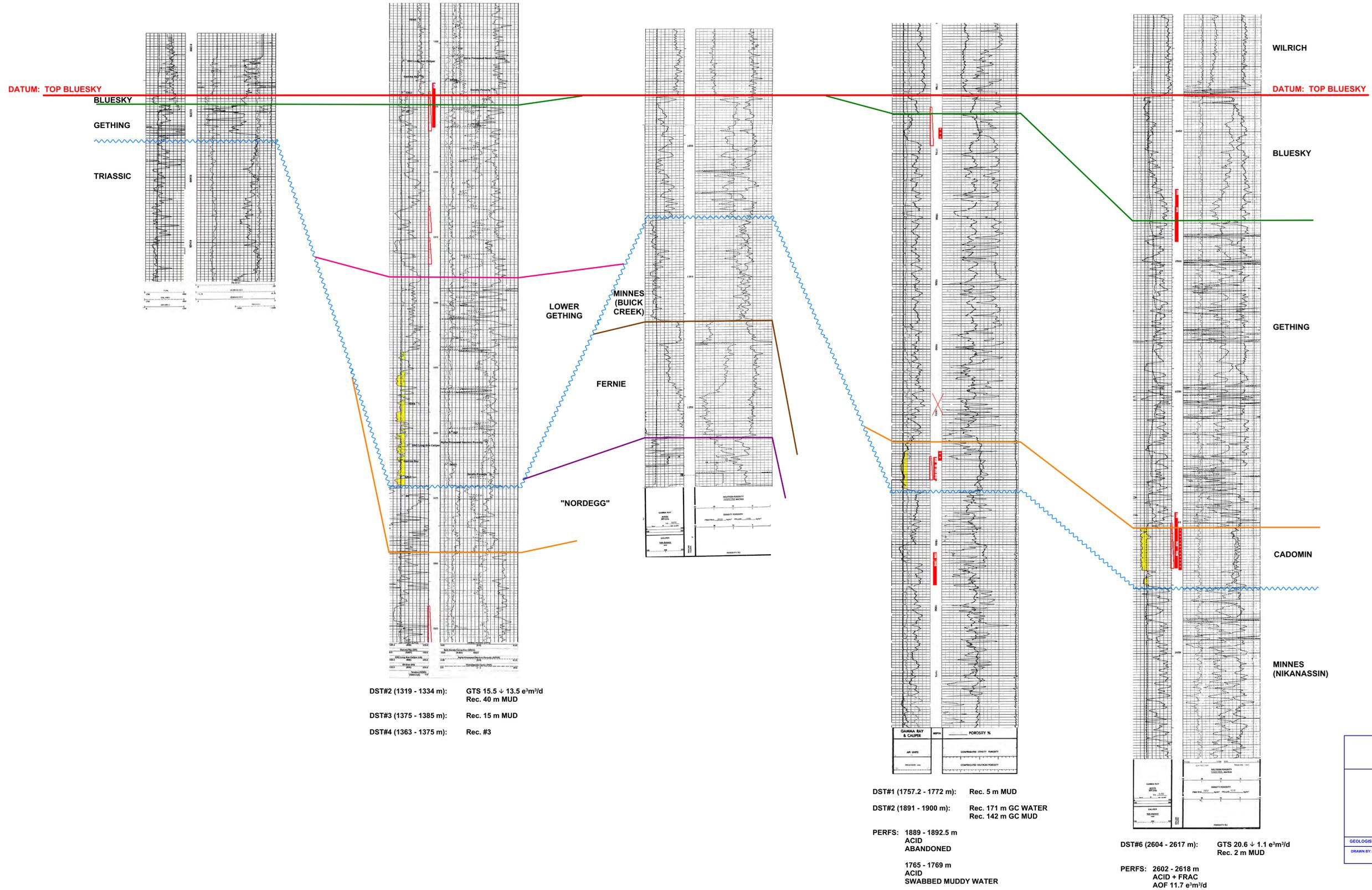
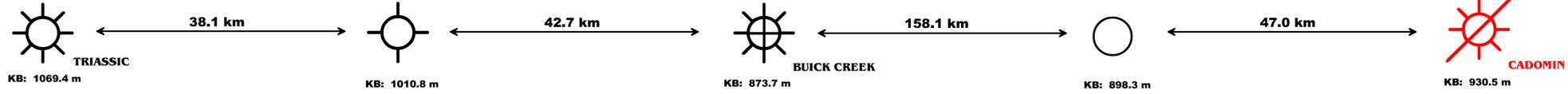
**ANADARKO JEDNEY  
b-62-E/94-G-8**

**UCEL W BEG  
b-59-C/94-G-1**

**REMINGTON ET AL INGA  
202/d-11-F/94-A-13**

**AEC BISSETTE  
12-3-77-16W6**

**CANHUNTER ESSO NOEL  
d-68-K/93-P-1**



**Petrel  
Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

**STRATIGRAPHIC CROSS-SECTION**  
**CDM - CDM'**  
**CADOMIN FORMATION**

GEOLOGIST: BRAD J. HAYES  
DRAWN BY: MARTIN PERRA  
PETREL ROBERTSON CONSULTING LTD. FEBRUARY 2003

**CANHUNTER SOUTH GRIZZLY**  
a-55-A/93-I-15

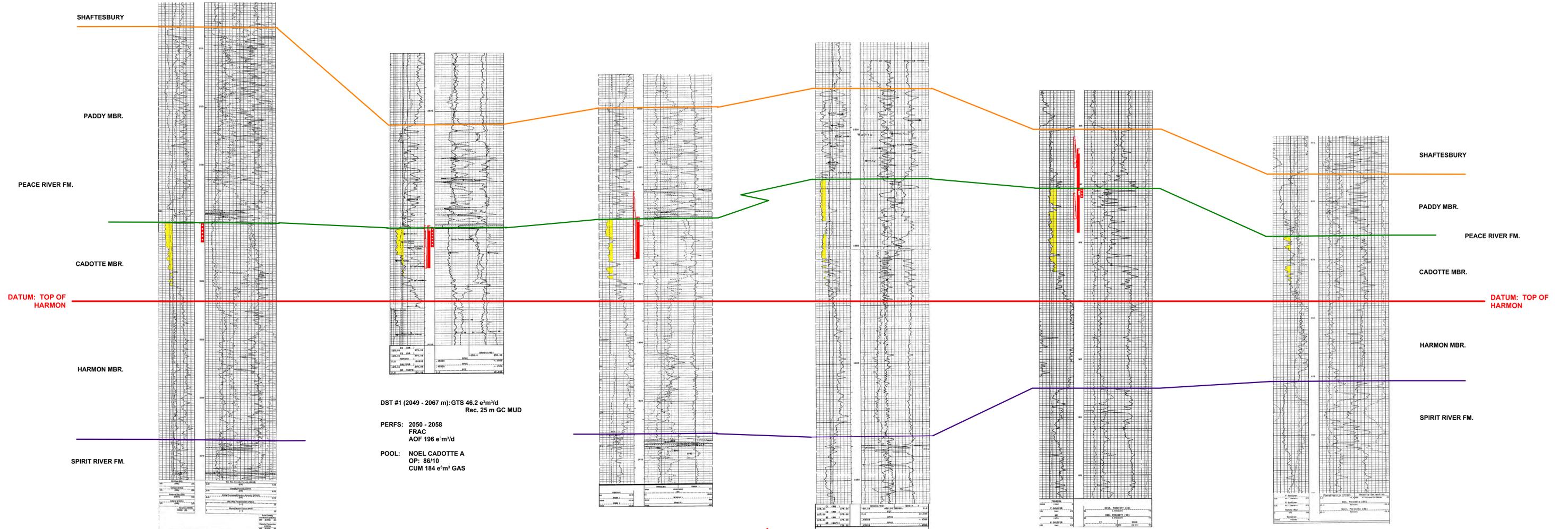
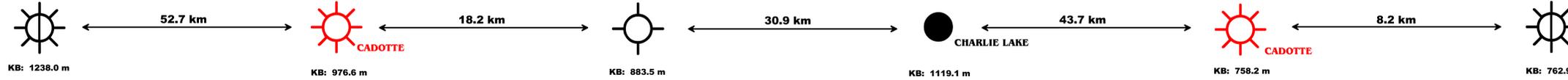
**CANHUNTER NOEL**  
b-24-A/93-P-7

**CANHUNTER ET AL JACKPINE**  
c-14-F/93-P-7

**CANHUNTER BRASSEY**  
d-46-F/93-P-10

**PENN WEST DAWSON**  
9-15-79-15W6

**PENN WEST ET AL DOE**  
9-11-80-15W6



DST #1 (2049 - 2067 m): GTS 46.2 e<sup>m</sup>/d  
Rec. 25 m GC MUD

PERFS: 2050 - 2058  
FRAC  
AOF 196 e<sup>m</sup>/d

POOL: NOEL CADOtte A  
OP: 86/10  
CUM 184 e<sup>m</sup> GAS

DST #1: GTS 0.14 ↓ 0 e<sup>m</sup>/d  
Rec. 12 m MUD

TWINNED - 02/d-46-H 93-P-10  
CADOtte AOF: 862 e<sup>m</sup>/d  
CUM: 79.5 e<sup>m</sup>/d

DST #1 (854 - 865 m): GTS 17.3 e<sup>m</sup>/d  
Rec. 213 m F WATER

PERFS: 852 - 856 m  
AOF 105 e<sup>m</sup>/d

POOL: DAWSON CREEK CADOtte A  
OP: 97/12  
CUM: 51.9 e<sup>m</sup>/d

PERFS: 2175 - 2183 m  
FRAC  
SWABBED - SMALL BLOW  
POTENTIAL GAS WELL

DEEP BASIN  
(REGIONAL GAS SATURATION,  
SUBNORMAL PRESSURE)

REGIONAL AQUIFER  
(NORMAL PRESSURE GRADIENT)



EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

STRATIGRAPHIC CROSS-SECTION

CDT - CDT

CADOtte MEMBER

GEOLOGIST: BRAD J. HAYES

DRAWN BY: KRISTA WALKER

FEBRUARY 2003

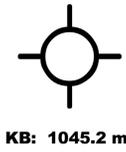
PETREL ROBERTSON CONSULTING LTD.

**CANHUNTER LYNX**  
**c-80-H/ 93-P-2**

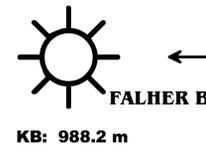
**CANHUNTER NOEL**  
**b-4-D/93-P-8**

**CANHUNTER ET AL KELLY**  
**a-3-B/93-P-1**

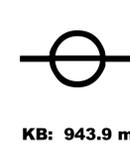
**PENGROWTH ET AL CUTBANK**  
**d-18-H/93-P-8**



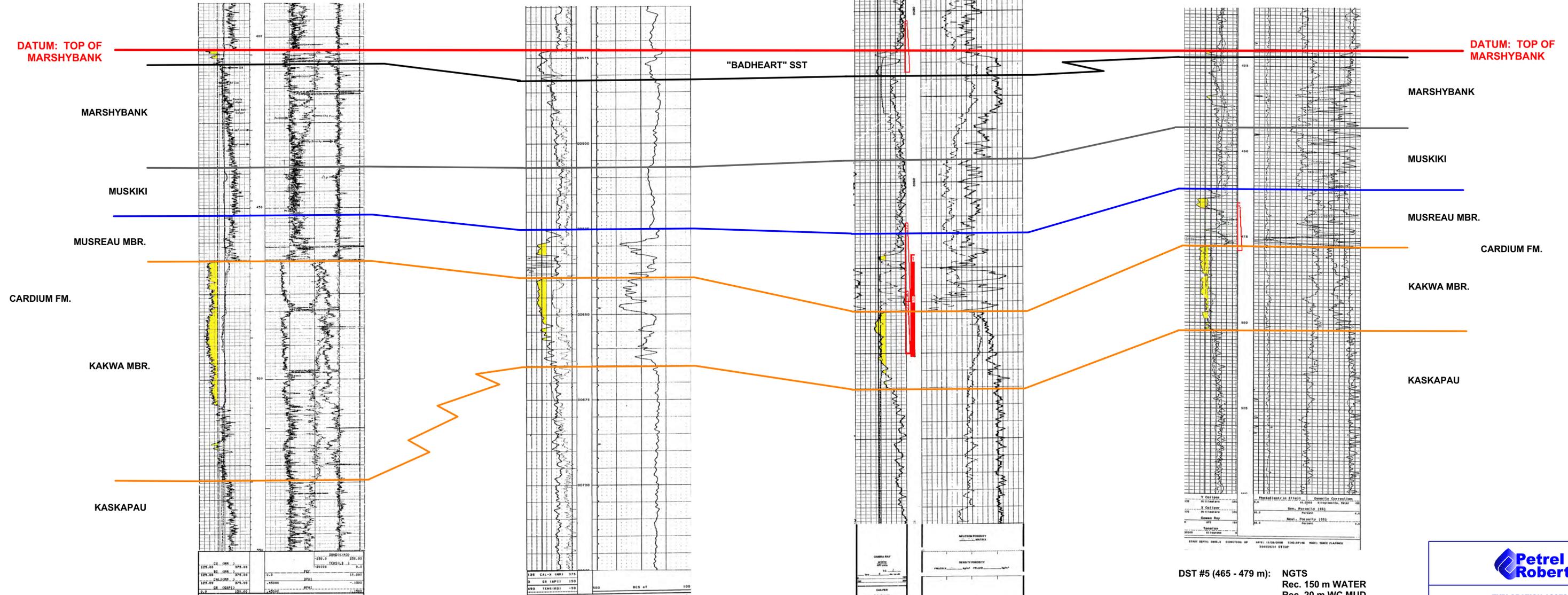
17.3 km



32.9 km



38.9 km



NOT TESTED

TWIN WELL - b-A4-D/93-P-8  
TEST 2100 m<sup>3</sup>/d GAS

DST #2 (912 - 935 m): NO RECOVERY (LOW PERM)

DST #3 (936 - 950.3 m): NO RECOVERY (NO PERM)

DST #5 (465 - 479 m): NGTS  
Rec. 150 m WATER  
Rec. 20 m WC MUD

**Petrel Robertson**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

STRATIGRAPHIC CROSS-SECTION  
**CRD - CRD'**  
CARDIUM FORMATION

GEOLOGIST: BRAD J. HAYES  
DRAWN BY: KRISTA WALKER  
PETREL ROBERTSON CONSULTING LTD.  
FEBRUARY 2003

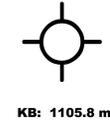
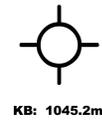
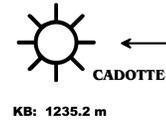
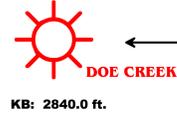
**CANHUNTER CUTBANK**  
d-93-A/93-P-8

**CANHUNTER ET AL MOOSE**  
a-7-H/93-P-6

**CANHUNTER LYNX**  
c-80-H/93-P-2

**CANHUNTER HIDING**  
d-77-G/93-I-16

**HUNT ET AL LYNX**  
10-28-61-9W6

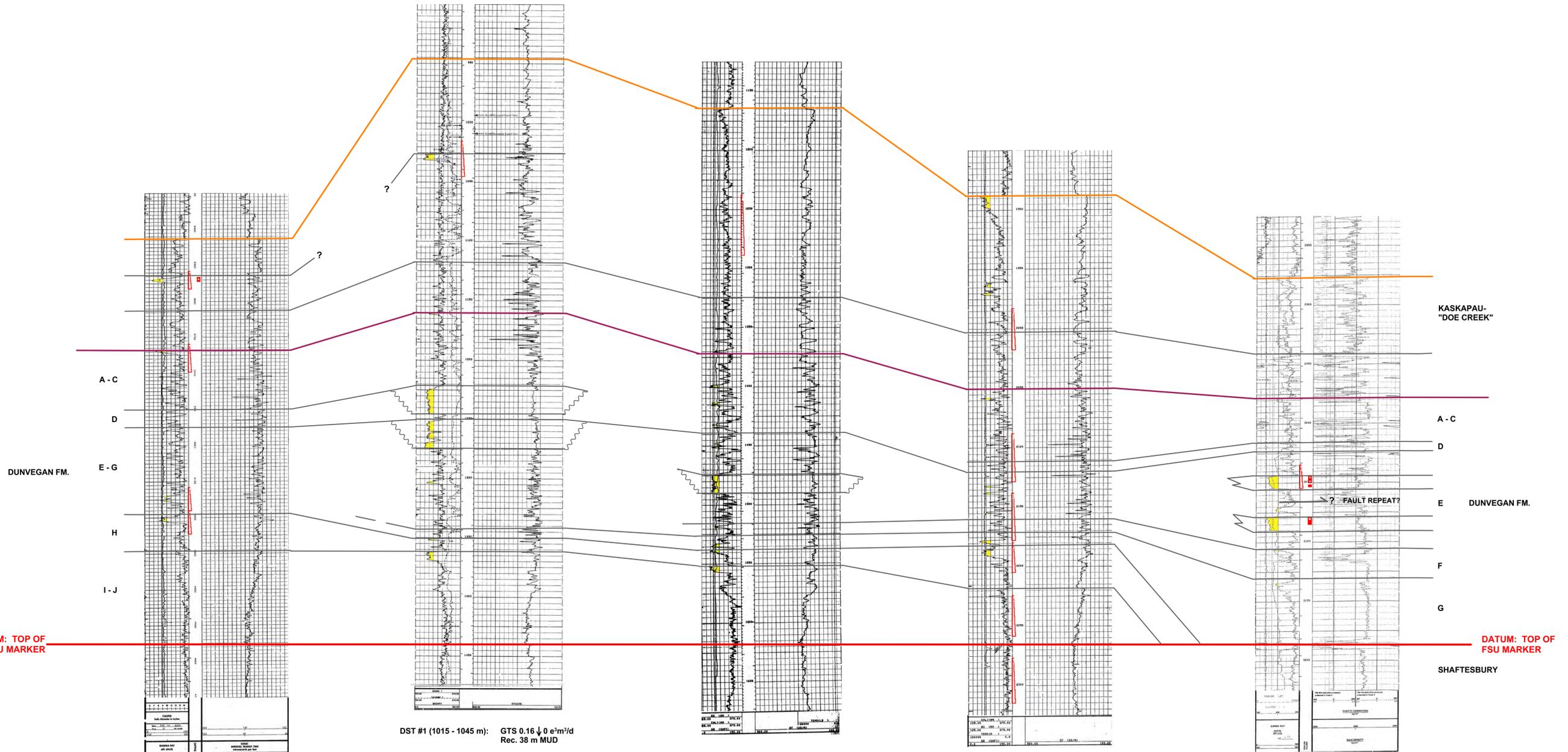


66.7 km

35.7 km

38.7 km

88.6 km



DATUM: TOP OF FSU MARKER

DATUM: TOP OF FSU MARKER

DST #3 (3517 - 3566'): GTS 29.3 e<sup>3</sup>m<sup>3</sup>/d  
Rec. 128 m GC MUD

DST #4 (3720 - 3797'): NGTS  
Rec. 4 m MUD

DST #5 (4117 - 4182'): Rec. 9 m MUD

DST #6 (4182 - 4247'): NGTS  
Rec. 9 m MUD

PERFS: 3534 - 3546'  
FRAC  
AOF: 140 e<sup>3</sup>m<sup>3</sup>/d

POOL: CUTBANK DOE CREEK A  
OP: 85/10  
CUM: 168 e<sup>3</sup>m<sup>3</sup> GAS

DST #1 (1015 - 1045 m): GTS 0.16 ↓ 0 e<sup>3</sup>m<sup>3</sup>/d  
Rec. 38 m MUD

DST #7 (1238 - 1289 m): Rec. 110 m MUD

DST #1 (2180 - 2205 m): GTS 0.49 ↓ 0.02 e<sup>3</sup>m<sup>3</sup>/d  
Rec. 15 m MUD

DST #10 (2138 - 2178 m): GTS 0.01 e<sup>3</sup>m<sup>3</sup>/d  
Rec. 16 m MUD

PERFS: 3044 - 3052 m, 3079 - 3085.5 m  
FRAC (LOWER PERFS)  
AOF: 369 e<sup>3</sup>m<sup>3</sup>/d

POOL: LYNX DUNVEGAN B  
OP: 82/08  
CUM: 474 e<sup>3</sup>m<sup>3</sup> GAS



EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

STRATIGRAPHIC CROSS-SECTION

**DUN - DUN'**  
DUNVEGAN FORMATION

GEOLOGIST: BRAD J. HAYES

DRAWN BY: KRISTA WALKER  
PETREL ROBERTSON CONSULTING LTD. FEBRUARY 2005

CANHUNTER TOMMY  
c-75-A/94-G-16



FETGP TOMMY  
c-20-A/94-G-16



NUMAC ET AL TOMMY  
a-63-I/94-G-9



PEX NORCEN TOMMY LAKES  
d-55-A/94-G-9



TPET ET AL CAMERON  
c-86-I/94-B-10



CANHUNTER STEWART  
6-1-80-23W6



6.5 km

7.7 km

19.1 km

95.2 km

115.6 km

DATUM: TOP DOIG/BASE HALFWAY

DATUM: TOP DOIG/BASE HALFWAY

BUCKINGHORSE (CRETACEOUS)

DOIG

DOIG PHOSPHATIC ZONE

HALFWAY

CHARLIE LAKE

HALFWAY

DOIG

PERFS: 990 - 964 m  
POOL: TOMMY LAKES HALFWAY A  
ON PROD: 94/03  
CUM: 9.1 e<sup>6</sup>m<sup>3</sup> GAS

DST#1 (1044 - 1052 m): GTS 144.9 ± 63.2 e<sup>6</sup>m<sup>3</sup>/d  
Rec. 5 m GSY MUD  
PERFS: 1056.5 - 1060 m, 1061.5 - 1068 m, 1070 - 1072 m  
FRAC AOF 332 e<sup>6</sup>m<sup>3</sup>/d  
POOL: TOMMY LAKES HALFWAY A  
ON PROD: 92/10  
CUM: 215 e<sup>6</sup>m<sup>3</sup> GAS

PERFS: 1351 - 1362 m  
FRAC AOF 23.4 e<sup>6</sup>m<sup>3</sup>/d  
POOL: 1373 - 1375  
ACID SWABBED TRACE OIL

PERFS: 2430 - 2468 m  
ACID SWABBED TRACE GTS ABANDONED

DOIG PHOSPHATIC ZONE

DST #8 (2035 - 2045 m): GTS 0.45 ± 0.23 e<sup>6</sup>m<sup>3</sup>/d  
Rec. 5 m GC MUD

DST #10 (2077 - 2121 m): Rec. 1 m MUD

**Petrel Roberts**  
EXPLORATION ASSESSMENT OF TIGHT GAS PLAYS, NORTHEASTERN BRITISH COLUMBIA  
STRATIGRAPHIC CROSS-SECTION  
HFY - HFY'  
HALFWAY FORMATION  
GEOLOGIST: BRAD J. HAYES  
DRAWN BY: MARTIN PEREA  
PETREL ROBERTSON CONSULTING LTD. FEBRUARY 2012

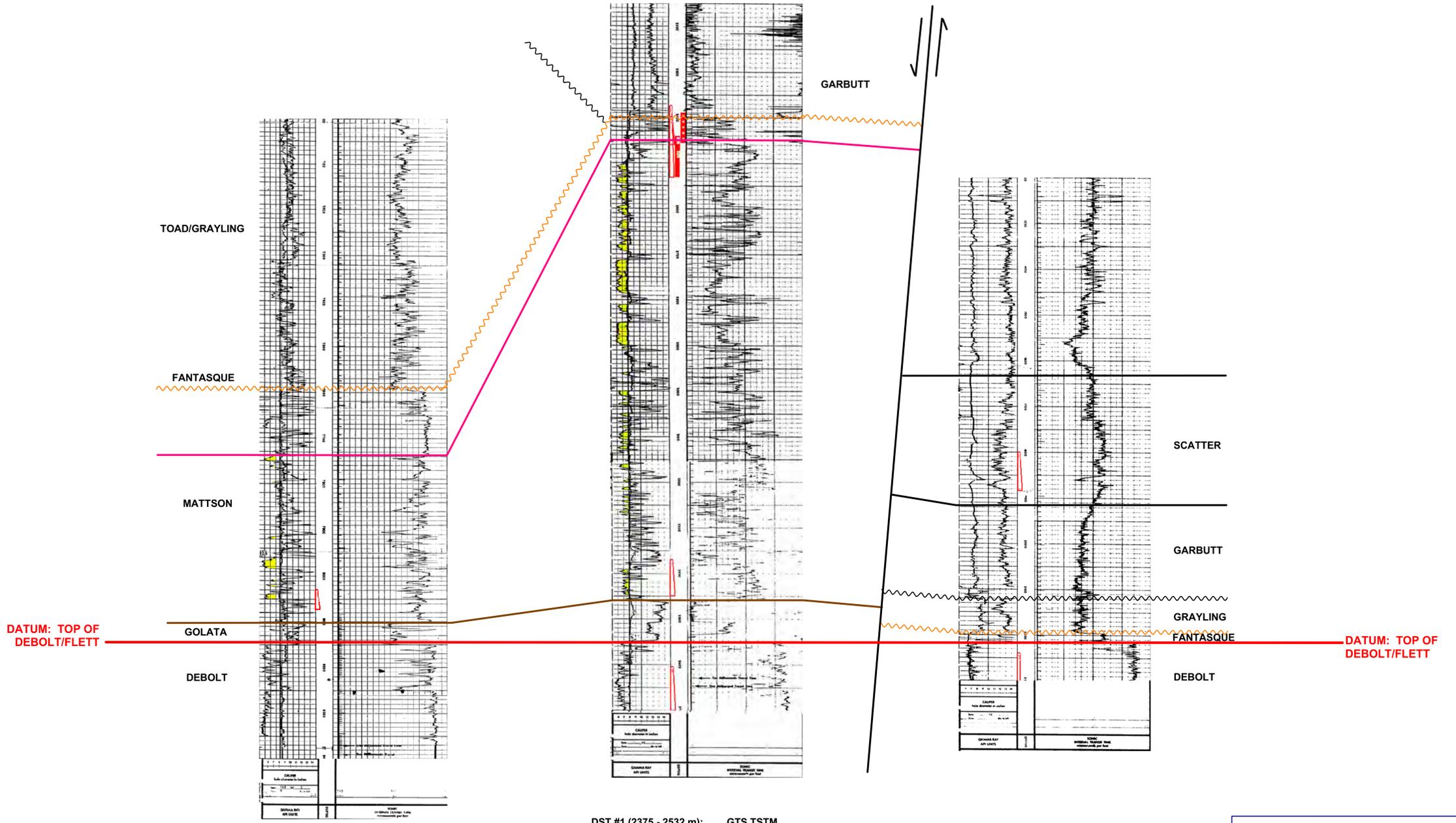
**MAT**  
SOUTHWEST

**MAT'**  
NORTHEAST

**GPD NOEL ET AL POPLAR**  
d-35-G/94-O-4

**ENCO ET AL TATTOO**  
a-78-L/94-O-10

**AMOCO HBOG TATTOO**  
d-77-K/94-O-10



DATUM: TOP OF DEBOLT/FLETT

DATUM: TOP OF DEBOLT/FLETT

DST #2 (8030 - 8072'): Rec. 80 m MUD

DST #1 (2375 - 2532 m): GTS TSTM  
Rec. 243 m WATER

DST#2 (2400 - 2460 m): GTS 30 e<sup>3</sup>m<sup>3</sup>/d  
Rec. 158 m S WATER

DST #3 (3370 - 3450 m): Rec. 213 m WATER

PERFS: 2392 - 2416 m, 2426 - 2456 m  
ACID  
AOF 73.6 e<sup>3</sup>m<sup>3</sup>/d

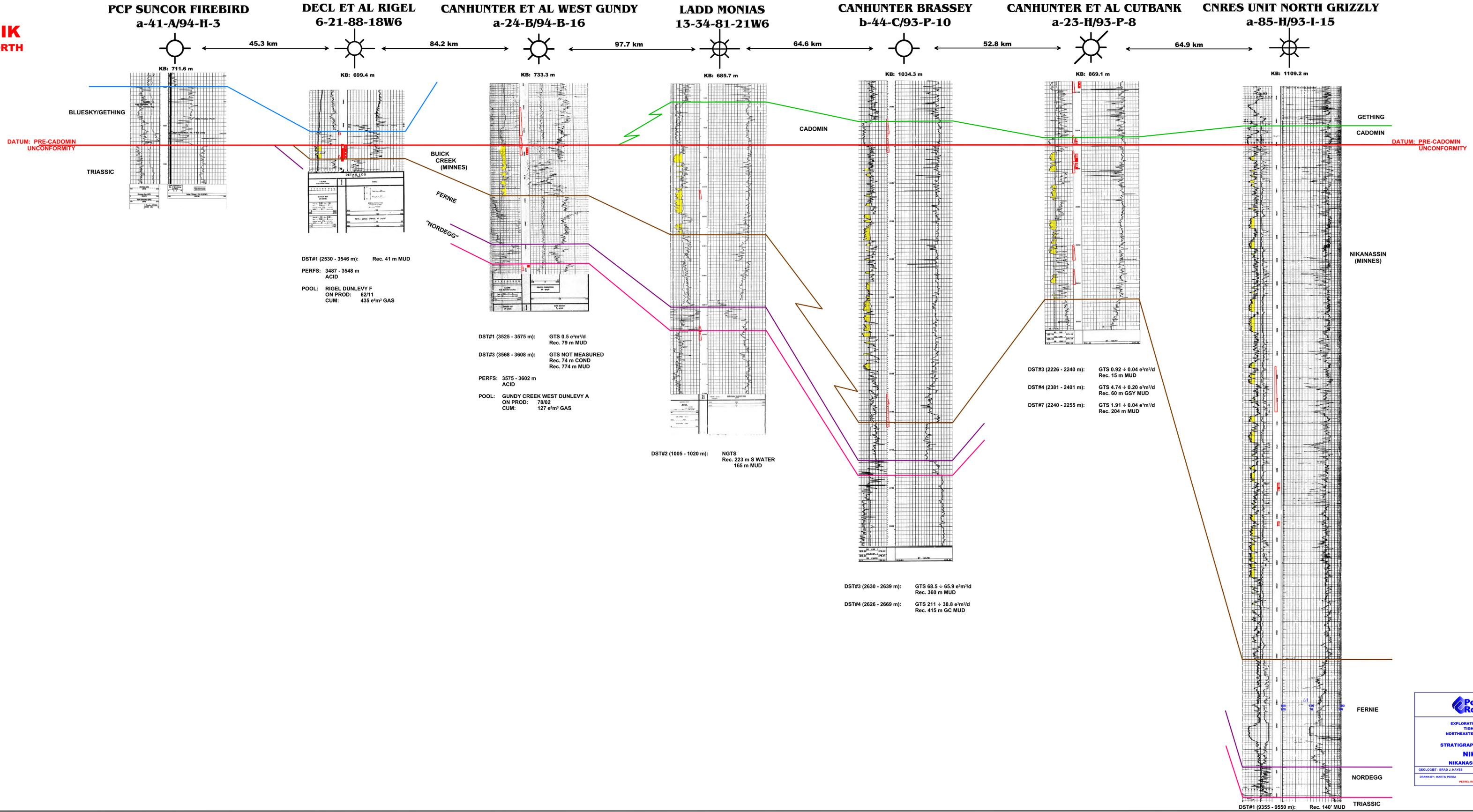
POOL: TATTOO MATTSON A  
ON PROD: 99/04  
CUM: 52.8 e<sup>3</sup>m<sup>3</sup> GAS

**Petrel Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

**STRATIGRAPHIC CROSS-SECTION**  
**MAT - MAT'**  
**MATTSON FORMATION**

GEOLOGIST: BRAD J. HAYES  
DRAWN BY: MARTIN PERRA  
PETREL ROBERTSON CONSULTING LTD. FEBRUARY 2003



**Petrel Roberts**  
 EXPLORATION ASSESSMENT OF  
 TIGHT GAS PLAYS,  
 NORTHEASTERN BRITISH COLUMBIA  
 STRATIGRAPHIC CROSS-SECTION  
**NIK - NIK**  
 NIKANASSIN FORMATION  
 GEOLOGIST: BRAD J. HAYES  
 DRAWN BY: MARTIN PERIA  
 FEBRUARY 2013  
 PETREL ROBERTSON CONSULTING LTD.

**HOME NORCEN BIRLEY**  
b-28-D/94-H-6

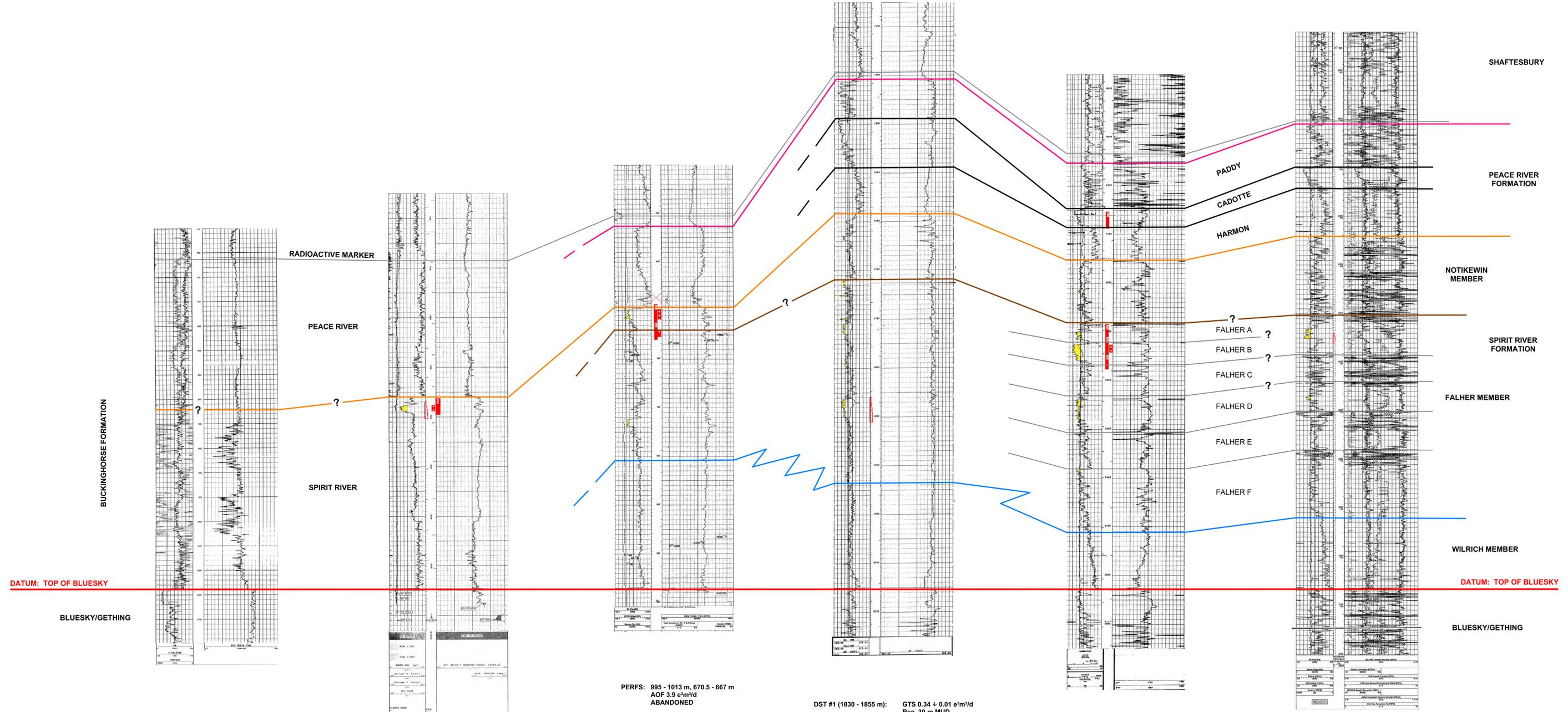
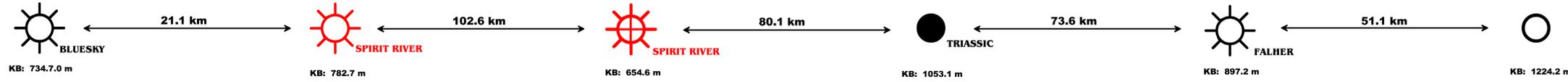
**ARL PICKELL**  
c-61-J/94-H-3

**HOME W. EAGLE**  
102/8-33-84-18W6

**CANHUNTER BRASSEY**  
d-13-F/93-P-10

**CANHUNTER KELLY**  
d-95-A/93-P-1

**BP NORTHSTAR OJAY**  
202/d-57-G/93-I-9



DATUM: TOP OF BLUESKY

DATUM: TOP OF BLUESKY

DST#1 (885 - 902 m): GTS 17.6 e<sup>m</sup>/d  
Rec. 78 m GSY MUD  
PERFS: 888 - 893 m  
FRAC  
POOL: PICKELL NOTIKEWIN A  
ON PROD: 01/02  
CUM: 19.6 e<sup>m</sup> GAS

PERFS: 995 - 1013 m, 670.5 - 667 m  
AOF 3.9 e<sup>m</sup>/d  
ABANDONED

DST #1 (1830 - 1855 m): GTS 0.34 ± 0.01 e<sup>m</sup>/d  
Rec. 30 m MUD

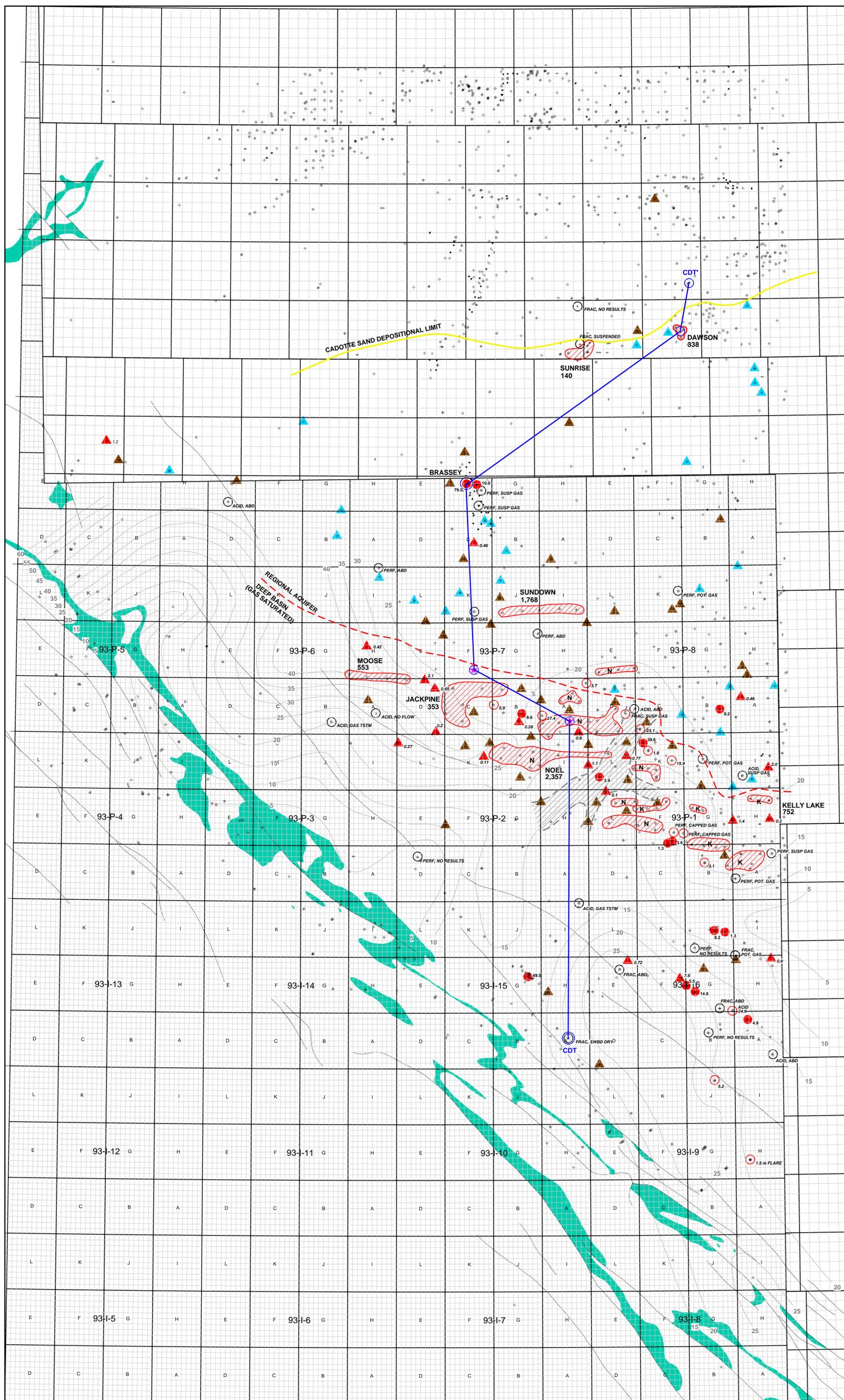
PERFS: 2263 - 2271 m  
ACID + FRAC  
POOL: KELLY FALHER B  
ON PROD: 86/09  
CUM: 96.3 e<sup>m</sup> GAS

DST#1 (2407 - 2422 m): GTS 0.12 ± 0.01 e<sup>m</sup>/d  
Rec. 20 m MUD

**Petrel Roberts**  
EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA  
STRATIGRAPHIC CROSS-SECTION  
**SR - SR'**  
SPIRIT RIVER GROUP  
GEOLOGIST: BRAD J. HAYES  
DRAWN BY: MARTIN PERDIA  
PETREL ROBERTSON CONSULTING LTD.  
FEBRUARY 2015

# SITUATION MAPS

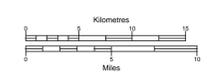
- **Cardium Formation**
- **Cadotte Member**
- **Mattson Formation**
- **Scatter Formation**
- **Jean Marie Member**
- **Sikanni Formation**
- **Dunvegan Formation**
- **Spirit River Formation**
- **Bluesky Formation**
- **Cadomin and Gething Formations**
- **Minnes Group**
- **Pardonet / Baldonnel Formations**
- **Halfway / Doig Formations**



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**LEGEND**

- ★ Core logged
- Cumulative Production
- OIL e<sup>3</sup>m<sup>3</sup>
- GAS e<sup>6</sup>m<sup>3</sup>
- ▲ Drillstem test recoveries
- ▲ OIL e<sup>3</sup>m<sup>3</sup>/day
- ▲ GAS e<sup>3</sup>m<sup>3</sup>/day
- ▲ MUD
- ▲ WATER
- Completion results e<sup>3</sup>m<sup>3</sup>/day
- Completion results e<sup>6</sup>m<sup>3</sup>
- Outcrop
- Thrust fault
- ZZZZ Valley incising Cadotte shoreface (Hayes, 1988)
- - - Up-dip Limit Deep Basin
- Line of cross-section
- Cadotte sand depositional limit
- ▨ Gas pool outline Initial Raw Reserves e<sup>6</sup>m<sup>3</sup>



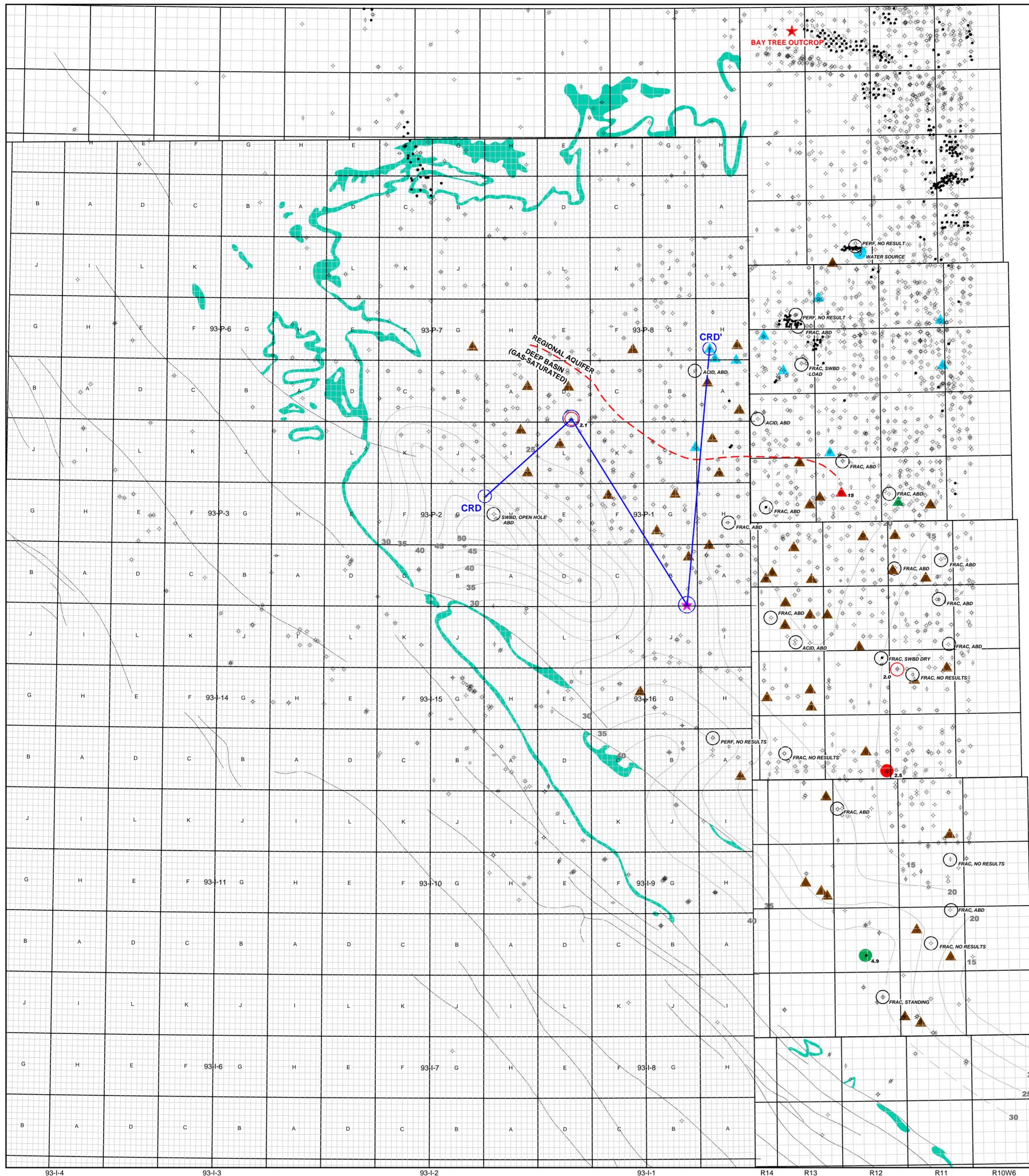
**Petrel Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

**CADOTTE MEMBER**

**SITUATION MAP**

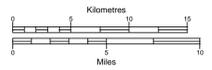
GEOLOGIST: BRAD J. HAYES 1:250 000 MAP 6  
DRAWN BY: KRISTA WALKER FEBRUARY 2003  
PETREL ROBERTSON CONSULTING LTD.



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T61

**LEGEND**

- ★ Core logged
- ★ Outcrop location
- Cumulative Production
  - OIL e<sup>3</sup>m<sup>3</sup>
  - GAS e<sup>6</sup>m<sup>3</sup>
- Drillstem test recoveries
  - ▲ OIL
  - ▲ GAS
  - ▲ MUD
  - ▲ WATER
- Completion results e<sup>3</sup>m<sup>3</sup>/day
- ~ Outcrop
- Thrust fault
- - - Deep Basin Limit
- Line of cross-section
- ~ Net clean sst contours (C.I. = 6m)



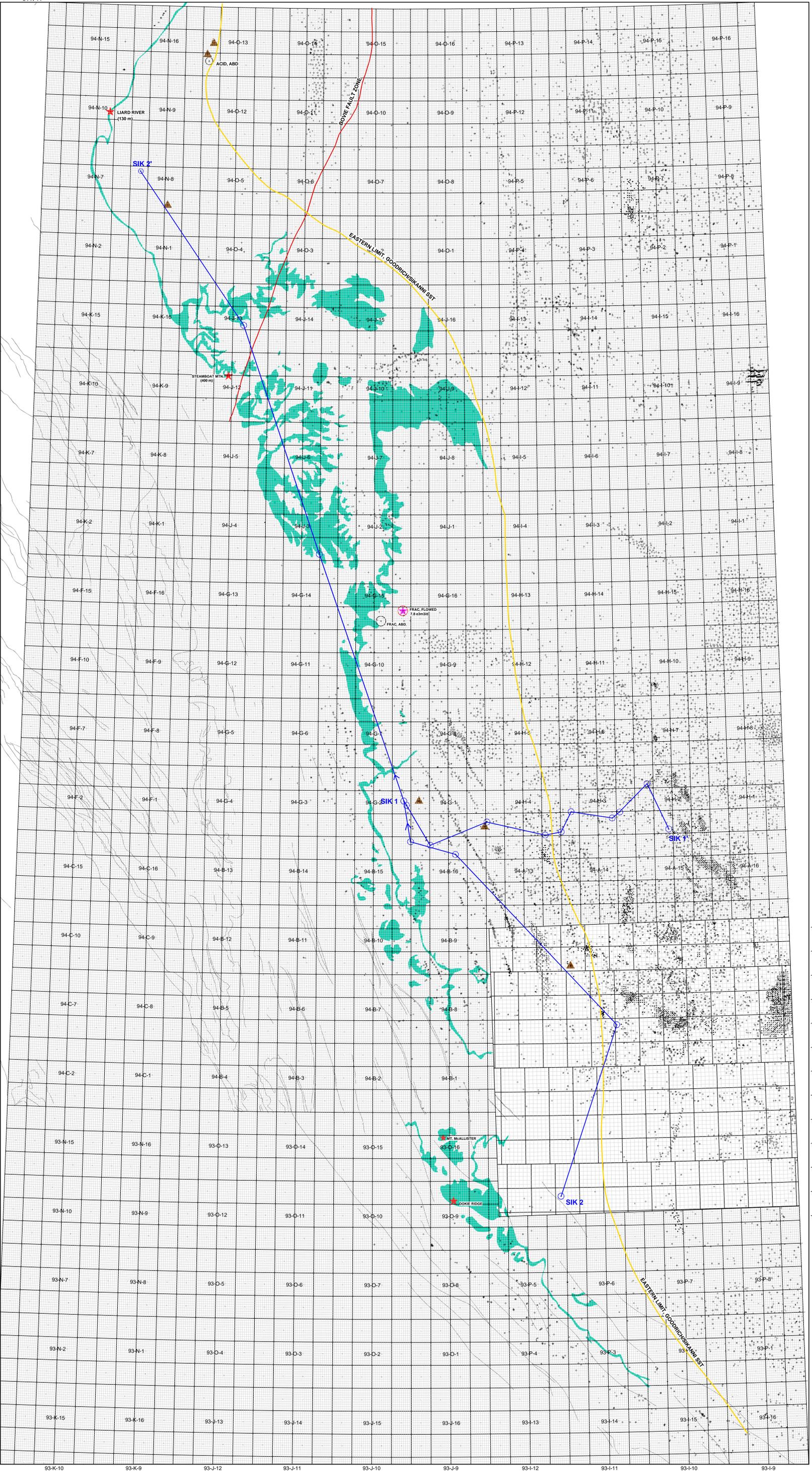
  
**EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA**  
**CARDIUM FORMATION**  
**SITUATION MAP**

GEOLOGIST: BRAD J. HAYES      1 : 250 000      MAP 2  
 DRAWN BY: KRISTA WALKER      PETREL ROBERTSON CONSULTING LTD.      FEBRUARY 2003

93-1-4      93-1-3      93-1-2      93-1-1      R14      R13      R12      R11      R10W6







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**LEGEND**

- ★ Core logged
- ★ Outcrop location
- Drillstem test recoveries
  - ▲ OIL
  - ▲ GAS
  - ▲ MUD
  - ▲ WATER
- Completion results
- Outcrop
- Thrust fault
- Eastern limit of Sikanni/Goodrich sst
- Line of cross-section

**Petrel Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA  
**SIKANNI and GOODRICH  
FORMATIONS**  
SITUATION MAP

GEOLOGIST: BRAD J. HAYES 1: 400 000 MAP 4  
DRAWN BY: KRISTA VALCIC FEBRUARY 2012  
PETREL ROBERTS CONSULTING LTD.





**LEGEND**

Drillstem test recoveries

- ▲ OIL
- ▲ GAS
- ▲ MUD
- ▲ WATER

Completion results  $e^3 m^3/day$

- ○

Outcrop

Thrust fault

Net clean sst contours (C.I. = 50m)

Structural boundaries

Line of cross-section

**Petrel  
Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

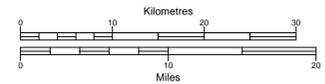
**SCATTER FORMATION**

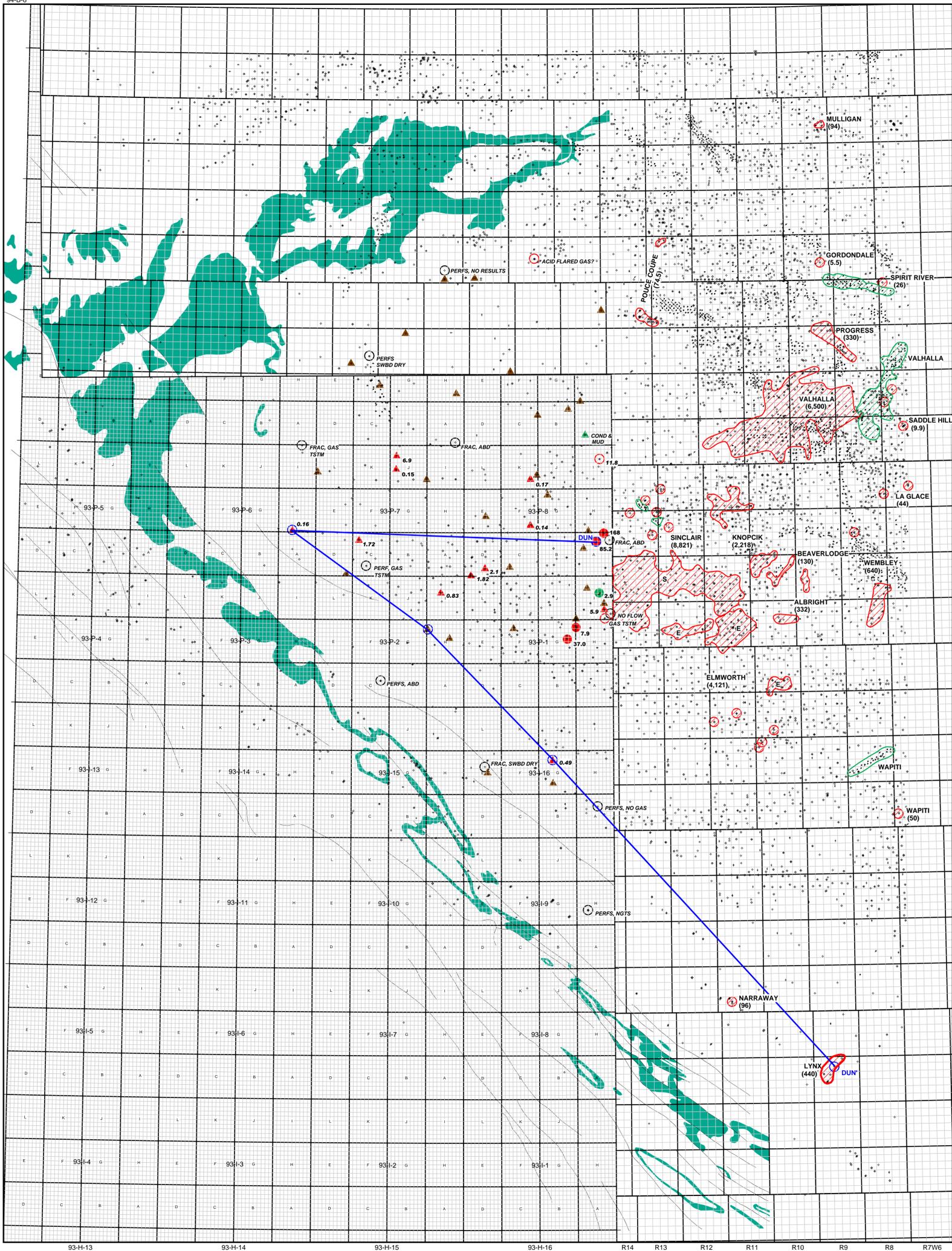
SITUATION MAP

GEOLOGIST: BRAD J. HAYES      1 : 400 000      MAP 5

DRAWN BY: KRISTA WALKER      FEBRUARY 2003

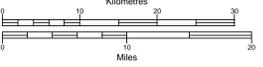
PETREL ROBERTSON CONSULTING LTD.





**LEGEND**

- Cumulative Production
  - OIL e<sup>3</sup>m<sup>3</sup> (Green circle)
  - GAS e<sup>6</sup>m<sup>3</sup> (Red circle)
- Drillstem test recoveries
  - OIL e<sup>3</sup>m<sup>3</sup>/day (Green triangle)
  - GAS e<sup>3</sup>m<sup>3</sup>/day (Red triangle)
  - MUD e<sup>3</sup>m<sup>3</sup>/day (Brown triangle)
  - WATER e<sup>3</sup>m<sup>3</sup>/day (Blue triangle)
- Completion results e<sup>3</sup>m<sup>3</sup>/day (Circle with number)
- Outcrop (Green wavy line)
- Thrust fault (Black line)
- Gas pool outline Marketable Gas e<sup>6</sup>m<sup>3</sup> (Red hatched area)
- Oil pool outline (Green hatched area)
- Line of cross-section (Blue line)



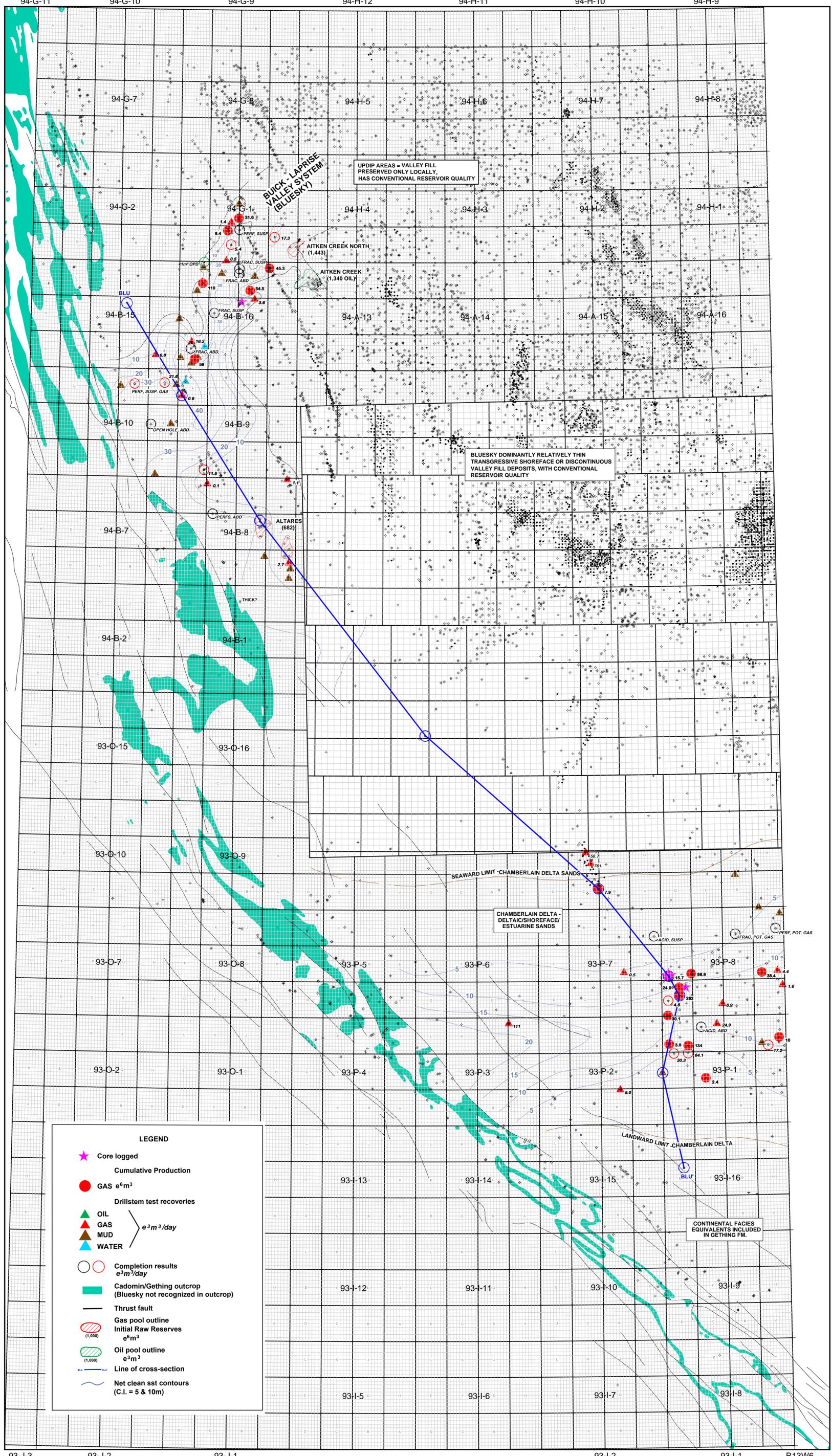
**Petrel Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

**DUNVEGAN FORMATION**

SITUATION MAP

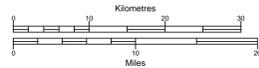
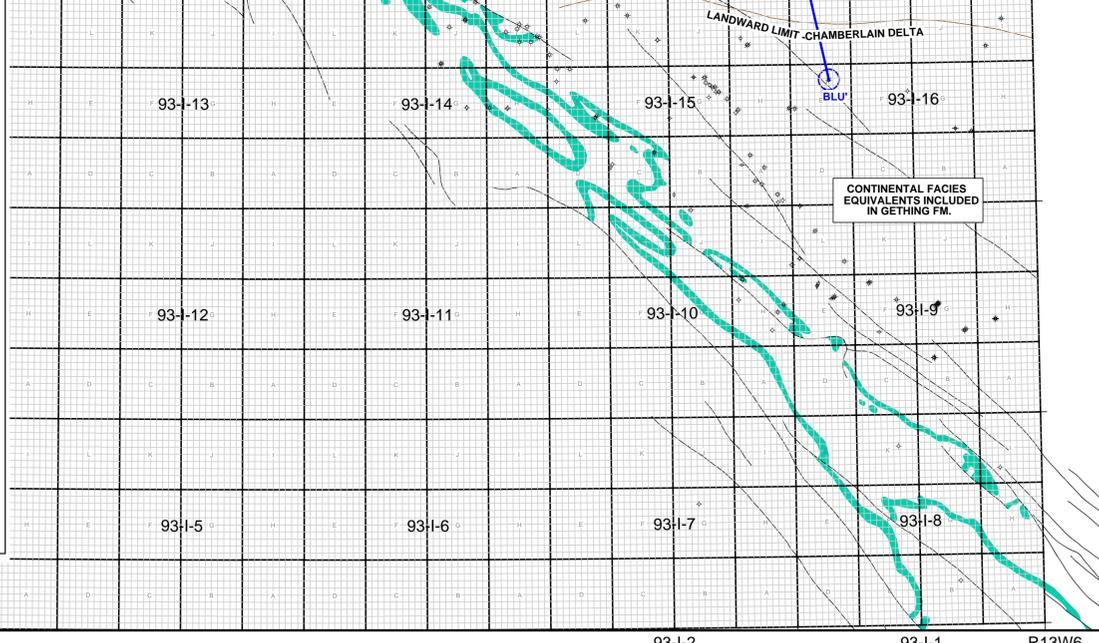
GEOLOGIST: BRAD J. HAYES 1:400 000 MAP 3  
DRAWN BY: KRISTA WALKER FEBRUARY 2003  
PETREL ROBERTSON CONSULTING LTD.



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**LEGEND**

- ★ Core logged
- Cumulative Production**
- GAS  $e^6 m^3$
- Drillstem test recoveries**
- ▲ OIL
- ▲ GAS
- ▲ MUD
- ▲ WATER
- Completion results  $e^3 m^3/day$
- Cadomin/Gething outcrop (Bluesky not recognized in outcrop)
- Thrust fault
- Gas pool outline Initial Raw Reserves  $e^6 m^3$
- Oil pool outline  $e^3 m^3$
- Line of cross-section
- Net clean sst contours (C.I. = 5 & 10m)



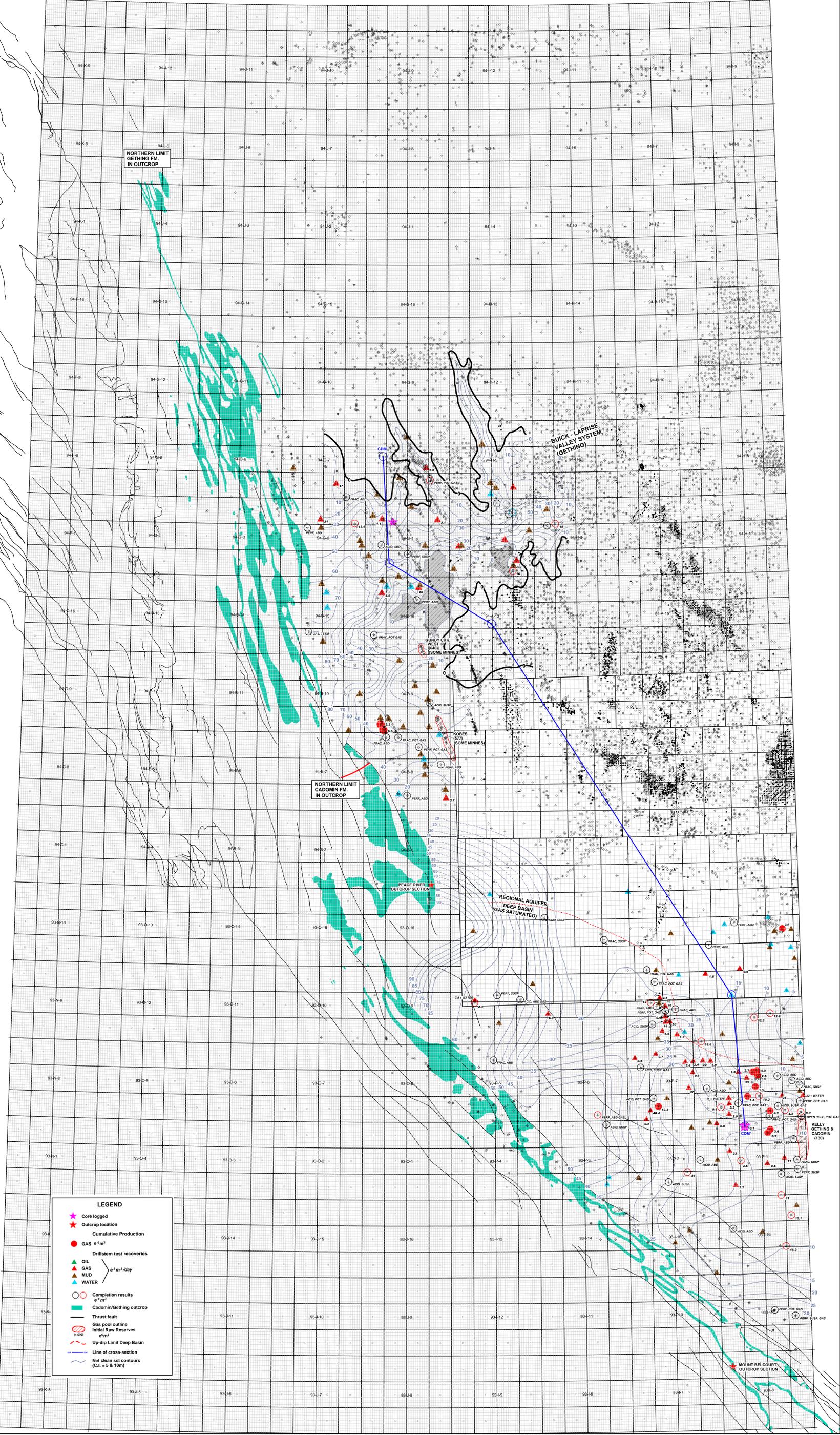
**Petrel Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA

**BLUESKY FORMATION**

SITUATION MAP

GEOLOGIST: BRAD J. HAYES 1: 400 000 MAP 8  
DRAWN BY: KRISTA WALKER FEBRUARY 2003  
PETREL ROBERTSON CONSULTING LTD.



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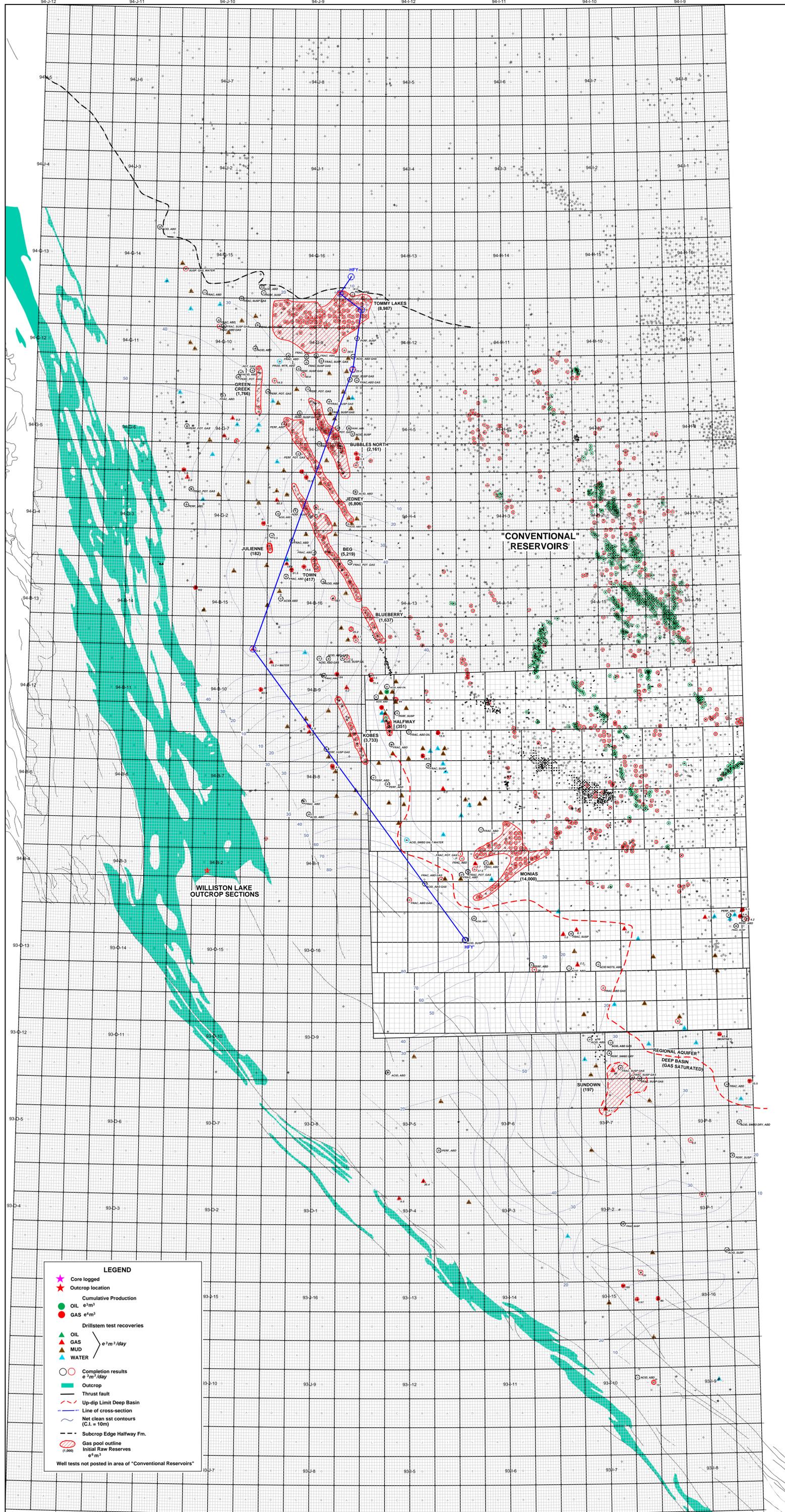
LEGEND	
★	Core logged
★	Outcrop location
Cumulative Production	
●	GAS e <sup>3</sup> m <sup>3</sup>
▲	OIL
▲	GAS
▲	MUD
▲	WATER
○	Completion results e <sup>3</sup> m <sup>3</sup>
■	Cadomin/Gething outcrop
—	Thrust fault
—	Gas pool outline
—	Initial Raw Reserves e <sup>3</sup> m <sup>3</sup>
—	Up-dip Limit Deep Basin
—	Line of cross-section
—	Net clean gas contours (C.I. = 5 & 10m)



**Petrel Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA  
**CADOMIN AND GETHING  
FORMATIONS**  
SITUATION MAP

GEOLOGIST: BRAD J. HAYES      1: 400 000      MAP 9  
DRAWN BY: KRISTA WALKER      FEBRUARY 2003  
PETREL ROBERTSON CONSULTING LTD.

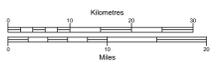


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**LEGEND**

- ★ Core logged
- ★ Outcrop location
- Cumulative Production
- OIL e<sup>3</sup>m<sup>3</sup>
- GAS e<sup>6</sup>m<sup>3</sup>
- ▲ Drillstem test recoveries
- ▲ OIL e<sup>3</sup>m<sup>3</sup>/day
- ▲ GAS e<sup>6</sup>m<sup>3</sup>/day
- ▲ MUD
- ▲ WATER
- Completion results e<sup>3</sup>m<sup>3</sup>/day
- Outcrop
- Thrust fault
- - - Up-dip Limit Deep Basin
- Line of cross-section
- Net clean sst contours (C.I. = 10m)
- - - Subcrop Edge Halfway Fm.
- Gas pool outline
- Initial Raw Reserves e<sup>6</sup>m<sup>3</sup>

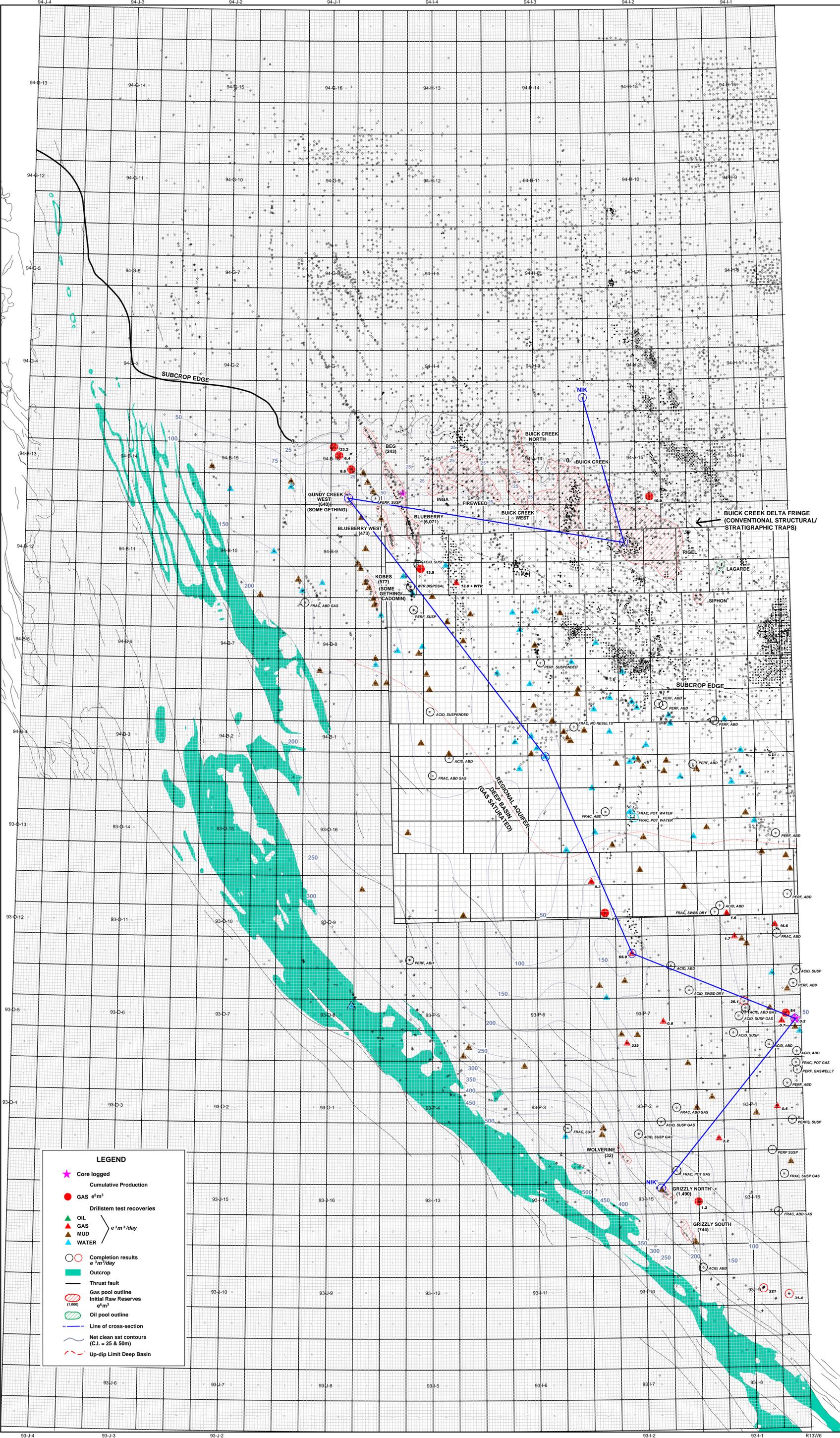
Well tests not posted in area of "Conventional Reservoirs"



**Petrel Roberts**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA  
**HALFWAY / DOIG  
FORMATIONS**  
SITUATION MAP

GEOLOGIST: BRAD J. HAYES 1: 400 000 MAP 12  
DRAWN BY: KRISTA WALKER FEBRUARY 2003  
PETREL ROBERTSON CONSULTING LTD.



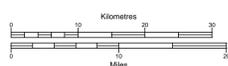
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**LEGEND**

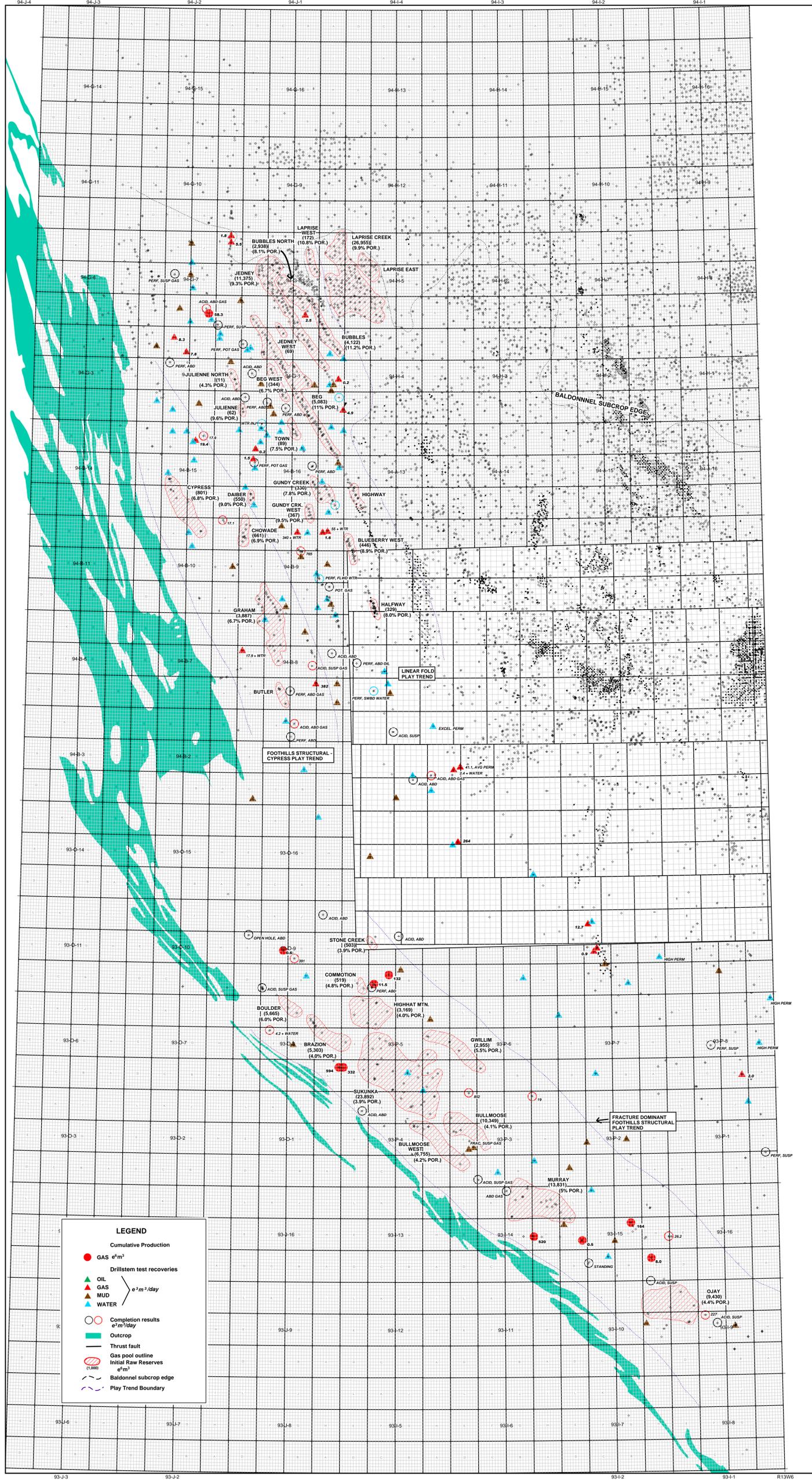
- ★ Core logged
- Cumulative Production
- GAS e<sup>6</sup>m<sup>3</sup>
- ▲ OIL e<sup>3</sup>m<sup>3</sup>/day
- ▲ GAS e<sup>3</sup>m<sup>3</sup>/day
- ▲ MUD e<sup>3</sup>m<sup>3</sup>/day
- ▲ WATER e<sup>3</sup>m<sup>3</sup>/day
- Completion results e<sup>3</sup>m<sup>3</sup>/day
- ▭ Outcrop
- Thrust fault
- ▭ Gas pool outline Initial Raw Reserves e<sup>6</sup>m<sup>3</sup>
- ▭ Oil pool outline
- Line of cross-section
- Net clean sst contours (C.I. = 25 & 50m)
- Up-dip Limit Deep Basin

  
 EXPLORATION ASSESSMENT OF  
 TIGHT GAS PLAYS,  
 NORTHEASTERN BRITISH COLUMBIA  
**MINNES GROUP**  
**(NIKANASSIN / BUICK CREEK)**  
 SITUATION MAP

GEOLOGIST: BRAD J. HAYES      1: 400 000      MAP 10  
 DRAWN BY: KRISTA WALKER      FEBRUARY 2003  
 PETREL ROBERTSON CONSULTING LTD.



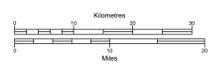
R13W6



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**LEGEND**

- Cumulative Production**
  - GAS e<sup>3</sup>m<sup>3</sup>
- Drillstem test recoveries**
  - ▲ OIL
  - ▲ GAS
  - ▲ MUD
  - ▲ WATER
- Completion results**
  - e<sup>3</sup>m<sup>3</sup>/day
- Outcrop**
  -
- Thrust fault**
  -
- Gas pool outline**
  -
- Initial Raw Reserves**
  - (e<sup>6</sup>m<sup>3</sup>)
- Baldonnel subcrop edge**
  -
- Play Trend Boundary**
  -

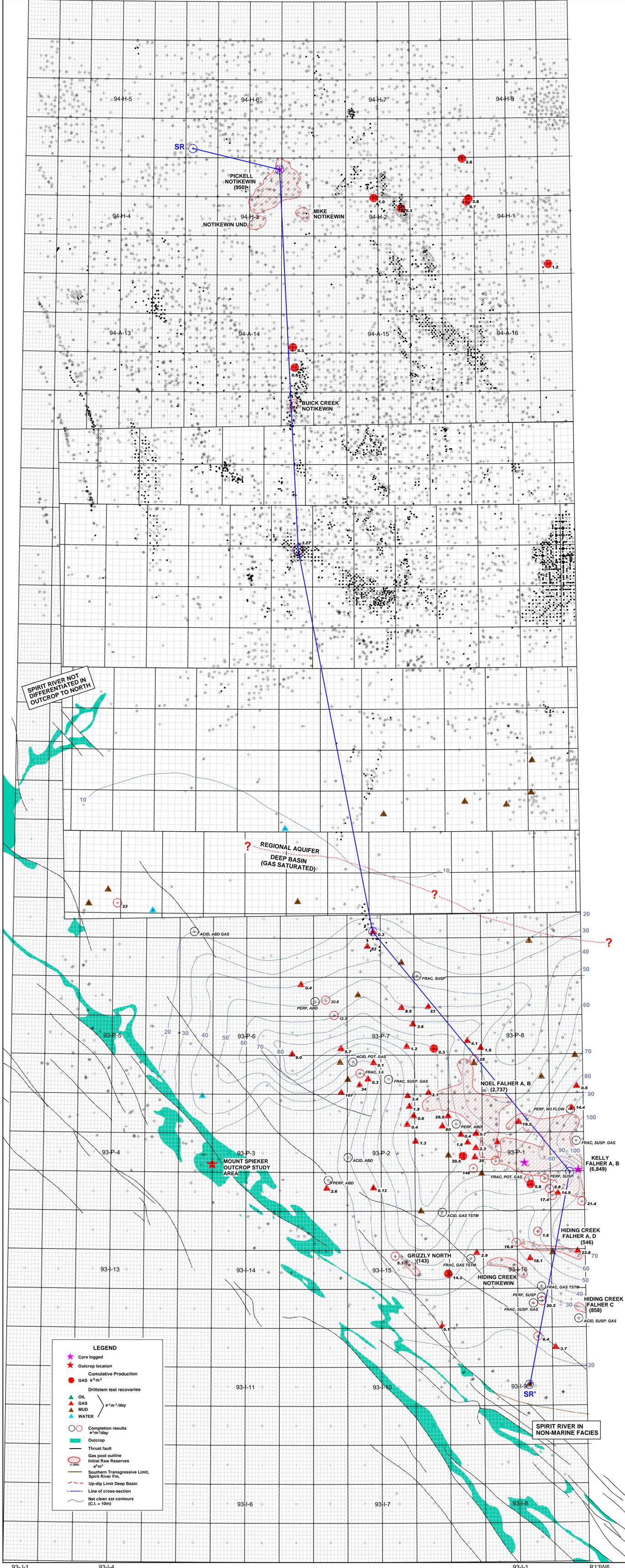


**Petrel Robertson**

EXPLORATION ASSESSMENT OF  
TIGHT GAS PLAYS,  
NORTHEASTERN BRITISH COLUMBIA  
**PARDONET / BALDONNEL  
FORMATIONS**  
SITUATION MAP

GEOLOGIST: BRAD J. HAYES 1:400 000 MAP 11  
DRAWN BY: KRISTA WALKER PETREL ROBERTSON CONSULTING LTD. FEBRUARY 2015

R13W6



SPRIT RIVER NOT DIFFERENTIATED IN OUTCROP TO NORTH

? REGIONAL AQUIFER DEEP BASIN (GAS SATURATED)

SPRIT RIVER IN NON-MARINE FACIES

- LEGEND**
- ★ Core logged
  - ★ Outcrop location
  - Cumulative Production GAS e<sup>3</sup>m<sup>3</sup>
  - Drillstem test recoveries
  - ▲ OIL e<sup>3</sup>m<sup>3</sup>/day
  - ▲ GAS e<sup>3</sup>m<sup>3</sup>/day
  - ▲ MUD e<sup>3</sup>m<sup>3</sup>/day
  - ▲ WATER e<sup>3</sup>m<sup>3</sup>/day
  - Completion results e<sup>3</sup>m<sup>3</sup>/day
  - Outcrop
  - Thrust fault
  - Gas pool outline
  - Initial Raw Reserves e<sup>3</sup>m<sup>3</sup>
  - Southern Transgressive Limit, Spirit River Fm.
  - Up-dip Limit Deep Basin
  - Line of cross-section
  - Net clean sst contours (C.I. = 10m)



**Petrel Roberts**

EXPLORATION ASSESSMENT OF TIGHT GAS PLAYS, NORTHEASTERN BRITISH COLUMBIA

**SPRIT RIVER FORMATION**

SITUATION MAP

GEOLOGIST: BRAD J. HAYES 1:250 000 MAP 7  
 DRAWN BY: KRISTA WALKER FEBRUARY 2003  
 PETREL ROBERTSON CONSULTING LTD.

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