HORN RIVER BASIN AQUIFER CHARACTERIZATION PROJECT

GEOLOGICAL REPORT

Prepared for:

HORN RIVER BASIN PRODUCERS GROUP
GEOSCIENCE B.C.

January, 2010

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EXECUTIVE SUMMARY

Study of subsurface stratigraphy in the Horn River Basin shows that three aquifers are potentially capable of supplying water for shale gas well completion operations (fracs), and accepting injection of spent frac fluids:

- Mississippian Debolt-Rundle carbonate platform
- Upper Mississippian Mattson sandstones
- Basal Cretaceous sandstones

The Debolt-Rundle carbonate platform can be subdivided into four units mappable across the basin – lower, middle, and upper Rundle, capped by the Debolt. Substantial reservoir quality occurs primarily at the top of the platform, as the result of leaching and dolomitization beneath the pre-Cretaceous unconformity (the “Detrital Zone”). Upper Rundle and Debolt strata appear to be most susceptible to reservoir enhancement, and thus the highest-quality and most continuous reservoir occurs along the upper Rundle and Debolt subcrops in the eastern part of the Horn River Basin.

Mattson deltaic to marginal marine sandstones occur only along the extreme western flank of the basin, and thicken rapidly west of the Bovie Fault Zone, into the Liard Basin. Reservoir quality ranges from poor to excellent, but well control is not sufficient for systematic mapping. The Mattson may offer very significant aquifer potential, but only to operators on the western margin of the Horn River Basin.

Basal Cretaceous strata occur in three settings:

- Gething fluvial strata fill a major south-north valley incised into the Mississippian carbonate platform along the eastern flank of the basin
- Bluesky shoreface successions were deposited along an east-west trend on the southern margin of the basin, flanking the Keg River Highlands, at the beginning of the regional transgression of the Wilrich / Clearwater Sea
- Chinkeh strata were deposited in a variety of non-marine to marine settings, forming a blanket in the eastern part of the Liard Basin, extending locally into the western Horn River Basin

While Cretaceous sandstones exhibit good reservoir quality locally, they are generally quite thin and laterally heterogeneous.

Reservoir quality mapping and hydrogeologic assessment were focused on the Debolt-Rundle succession. Net porous reservoir and porosity-thickness maps were constructed using sample cuttings observations and well logs; assumptions and approximations had to be applied because of the highly heterogeneous nature of the "Detrital Zone". Pressure-elevation graphs demonstrate a regionally-continuous aquifer system, in hydrostratigraphic continuity with overlying Cretaceous sandstones.

Water analyses show total dissolved solids to range from <15,000 to >40,000 mg/l, indicating Debolt-Rundle waters are non-potable, but suitable for use as frac fluids.

H_2S was found to be present in many gas analyses, and was noted on some daily reports during pumping and injection tests. Although concentrations are generally low in Mississippian and Cretaceous fluids, they are sufficient to warrant caution in operations and equipment design. Additional work will be required to determine how to handle H_2S in high-volume water production and injection operations.

Immense water volumes – more than 10 billion m^3 – are present in Mississippian carbonate strata with enhanced reservoir quality, and far larger volumes in lower-quality regional Mississippian carbonates. Core and DST analyses demonstrate that permeabilities are low in regional strata, and cannot support high-rate pumping and injection. However, well-test data and modeling indicate that long-term, high-rate water production and injection is possible from the large reservoir volumes mapped along the eastern flank of the Horn River Basin.

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INTRODUCTION

Devonian shales of the Horn River Basin in northeastern British Columbia are the focus for one of the leading shale gas plays in North America. Economic gas production requires drilling of up to 16 multileg horizontal wells from a single drilling pad, and conducting up to 16 staged hydraulic fracture stimulation (frac) jobs in each horizontal leg. Each frac injects up to 4000 m^3 of water into the reservoir, along with chemicals and proppants to ensure that the rock is effectively fractured, and that fractures remain open. Upon completion, the well flows back some of this water, contaminated by the injected chemicals.

Literally thousands of wells will be drilled to fully develop the Horn River Basin shale gas play. Enormous volumes of water will be required for reservoir stimulation (fracing), and safe disposal must be ensured for equally huge volumes of produced water. Deep subsurface aquifers, carrying non-potable water and lying far below the water table and domestic water wells, represent ideal sources and sinks for the water volumes required. Shallower aquifers, such as buried valley fills associated with Quaternary glaciation and drainage, are less desirable targets, as there is less separation from surface and well waters. Surface waters may serve as isolated, short-term water sources, but surface disposal of frac fluids will not be contemplated.

The petroleum industry is in its infancy in the Horn River Basin, and so we suffer from lack of well control and other information to support characterization of subsurface aquifers. While numerous wells have been drilled on the basin margins for conventional gas reservoirs, there are relatively few wells in the basin proper, and large areas remain virtually undrilled. New wells target the Devonian gas shales, and most new geological study has focused on their reservoir characteristics. Within the past year, however, many operators have begun to drill water source and disposal wells on their properties, and are working toward understanding subsurface aquifers as potential water sources and sinks.

To determine whether subsurface aquifers have sufficient water volumes and flow capacity to support long-term development in the Horn River Basin, comprehensive regional mapping and reservoir characterization is required. The Horn River Basin Producers Group (HRBPG), a consortium of industry operators, recognized this issue in 2008, and asked Geoscience B.C. to undertake such a study. Geoscience B.C. commissioned Petrel Robertson Consulting Ltd. to develop a project workplan, manage the collection of test data from new HRBPG wells, undertake the required technical work, and to produce this report summarizing the findings.

STUDY PARTICIPANTS

GEOSCIENCE B.C. initiated and managed the Horn River Basin Reservoir Characterization Project, and provided funding to support the geological studies, as well as the collection of supplemental test data from new water source and disposal wells. Geoscience BC is an industry-led, not-for-profit, applied geoscience organization. It works in partnership with industry, academia, government, First Nations, and communities to fund applied geoscience projects with the objective to attract mineral and oil and gas exploration to British Columbia. Geoscience BC's mandate includes the collection, interpretation, and delivery of geoscience data and expertise, to promote investment in resource exploration and development in British Columbia. Its involvement in the Horn River Basin has been supported by a targeted $5 million grant from the Province of British Columbia.

Members of the HORN RIVER BASIN PRODUCERS GROUP (HRBPG) provided confidential data and logistical support to the Project. The includes representatives from eleven companies with leases in the Horn River Basin. They meet regularly to discuss aspects of responsible development of the resources such as minimizing cumulative environmental impact through methods such as multi-well pad drilling and common infrastructure (roads, pipelines, utilities, water use, etc.). A key priority for the companies is to work with First Nations, government and communities to understand and address issues and to manage expectations around economic and social impacts.

PETREL ROBERTSON CONSULTING LTD. (PRCL) managed geoscience work for the Project, creating the stratigraphic framework and mapping, then folding in petrographic and hydrogeologic contributions from affiliated consultants, and producing this final report. PRCL is Canada's leading petroleum geoscience and exploration consultancy. Working with several affiliated consultants, PRCL leads projects ranging from regional exploration assessments to local reservoir characterization and mapping.

CANADIAN DISCOVERY LTD. compiled and interpreted reservoir test data, to provide an integrated hydrogeologic framework for the Project. Canadian Discovery provides fully-integrated geoscience services to a diverse range of resource sector stakeholders including multi-client projects, information products, geoscience consulting, and data/software.

JC CONSULTING INC. and JMS GEOLOGICAL CONSULTING described and documented reservoir characteristics from sample cuttings for 63 wells in and bordering the Horn River Basin. These companies undertake core and cuttings evaluation for land sale evaluations, exploration, and regional play generation. They also evaluate reservoirs for post-drill analysis and formation damage, and specialize in visual permeability estimation from drill cuttings.

REGIONAL SETTING

The Horn River Basin (HRB) lies in northeastern British Columbia, and is bounded to the east and south by Devonian carbonate platforms of the Keg River, Sulphur Point, and Slave Point Formations (Map 1). To the west, a major structural feature – the Bovie Fault Zone – separates the HRB from the Liard Basin to the west. The Horn River Basin continues northward into the Northwest Territories, but land, infrastructure, and regulatory issues confine oil and gas activity to the B.C. portion.

Structure maps on the top of the Banff Formation and the basal Cretaceous radioactive marker show a fairly uniform north-northeasterly dip in the eastern half of the basin (Maps 2, 3). A closed structural high appears in the southwest, and a closed low in the west to northwest, but these are based upon very scanty well control. A high level of structural complexity is evident in the Bovie Fault Zone, and structural elevations are much lower in the Liard Basin to the west (see discussion below). Map 4 illustrates drill depth to the pre-Cretaceous unconformity, which is the level where most aquifer potential is found.

Shale gas targets of the HRB occur in the siliceous, organic-rich Evie and Muskwa shale members of the Middle to Upper Devonian Horn River Formation. Westward and northward of the Slave Point / Sulphur Point / Keg River carbonate platform margins, the Horn River Formation forms the basal part of a thick Mississippian – Devonian shale section (Fig. 1). Stacked carbonate ramps/platforms of the Mississippian Rundle Group and Debolt Formation prograde across the Horn River Basin, passing basinward into the Prophet and Besa River formations to the west and north (Richards, 1989; Richards et al., 1993) (Fig. 2). Cretaceous Buckinghorse shales lie unconformably on the Mississippian carbonates, except on the southern and eastern margins of the Basin, where basal Cretaceous sandstones are assigned to the Bluesky and Gething formations, respectively. Quaternary glacial deposits up to 100-150 metres thick cap the Buckinghorse and Upper Cretaceous Dunvegan sandstones and conglomerates, which are preserved locally (Fig. 1).

Westward across the Bovie Fault Zone, the top of the Mississippian carbonate ramp drops approximately 1000 metres, and the overlying section thickens correspondingly (Fig. 2; Maps 2, 3). The structural history of the Bovie Fault Zone is complex, as interpreted by McLean and Morrow (2004), so that accurate correlations and mapping require seismic support (e.g., Fig. 3). The uppermost Mississippian Mattson Formation, a sand-dominated deltaic succession, lies on the carbonate platform above transgressive Golata shales, and thickens rapidly westward from the BFZ to several hundred metres. Cherts and sandstones of the Permian Fantasque Formation cap an unconformity overlying the Mattson. The Triassic Toad and Grayling formations are primarily siltstone and shale equivalents to the Montney of the Peace River area.

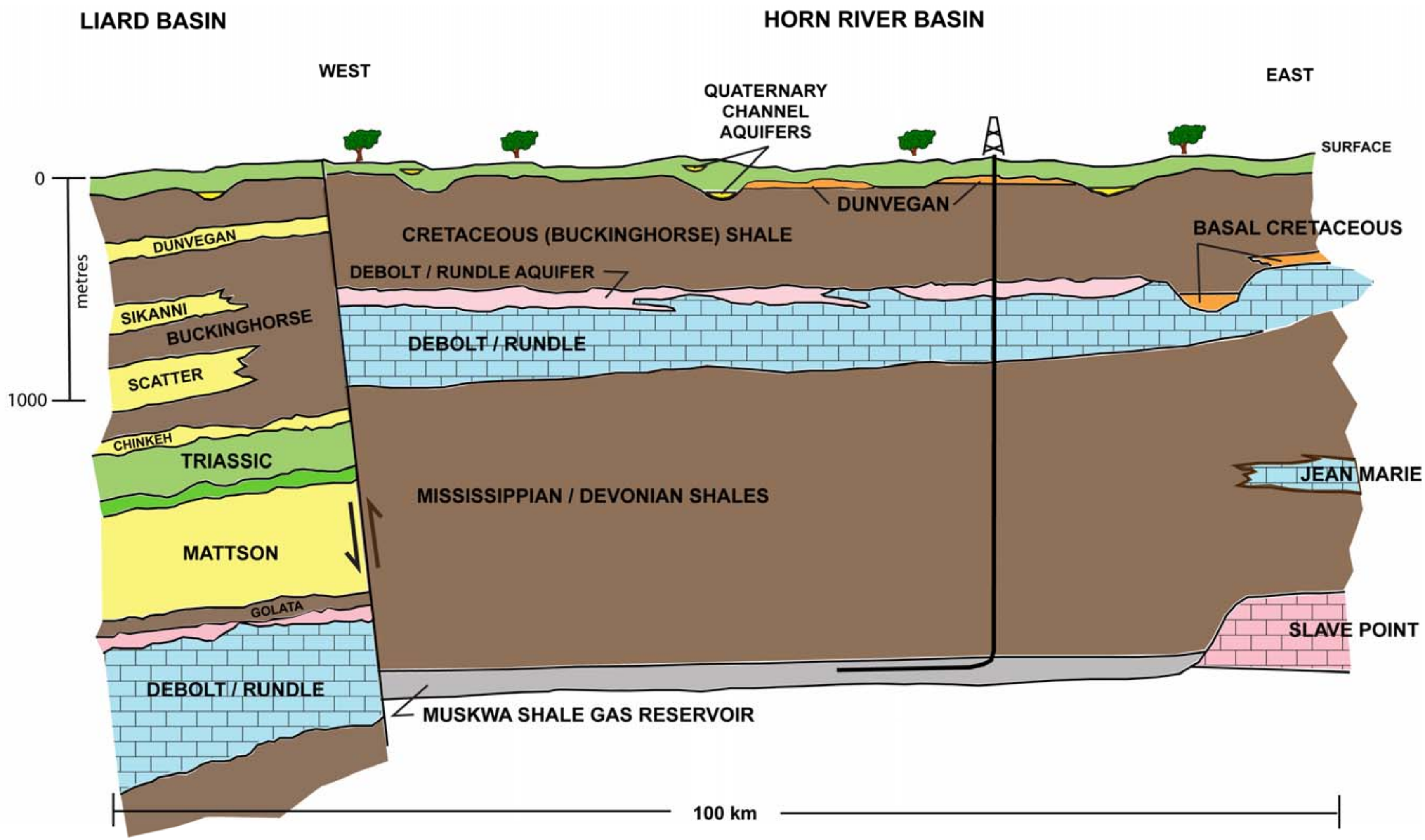


Figure 1. Schematic stratigraphic cross-section, Horn River Basin and adjacent Liard Basin.

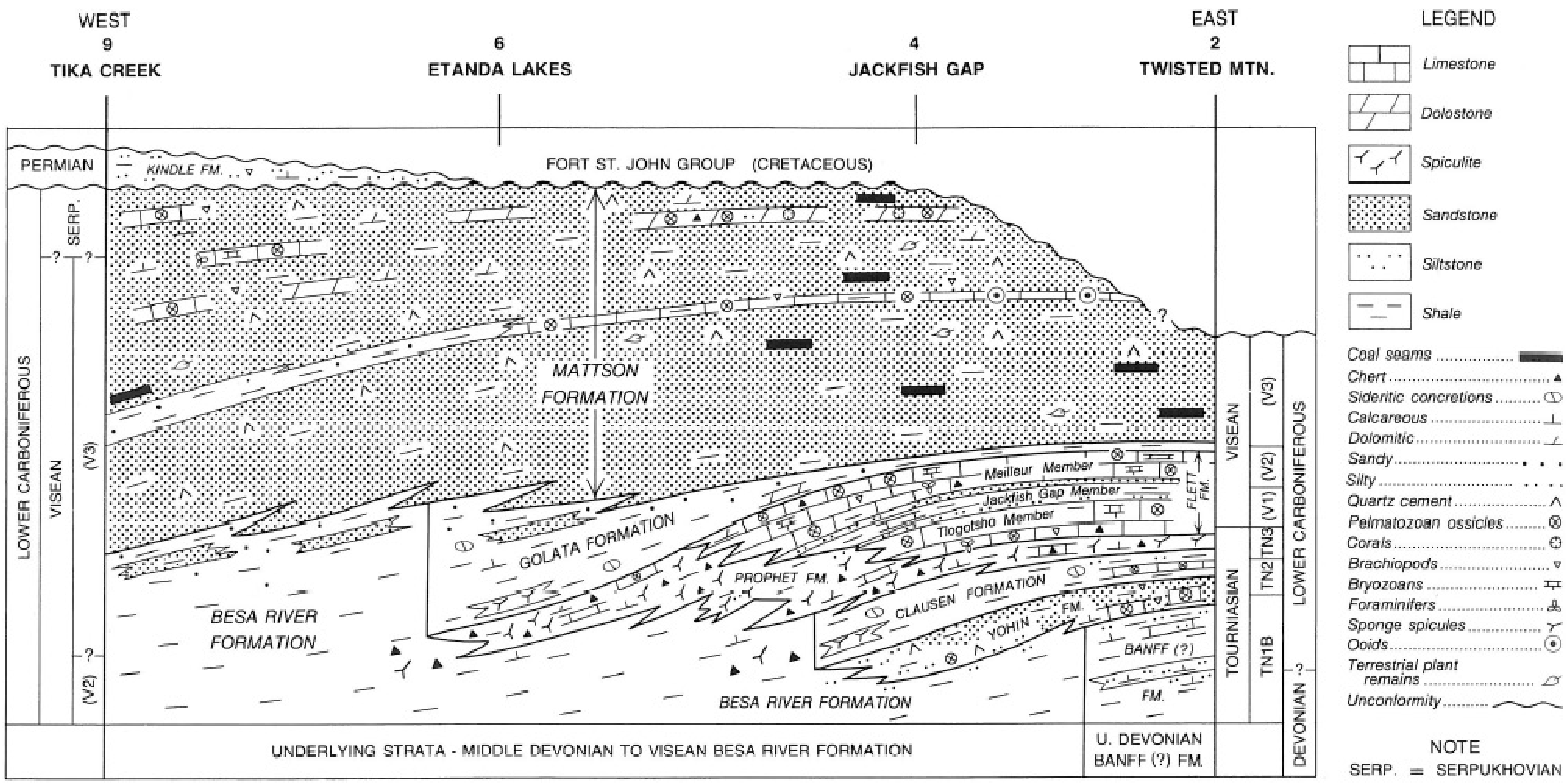
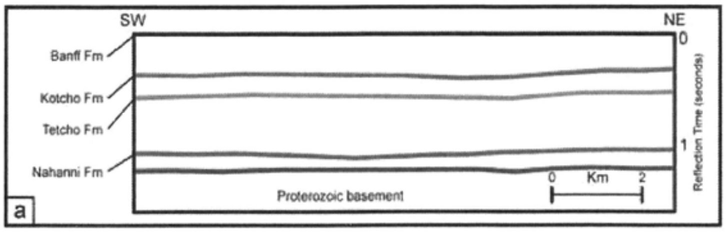
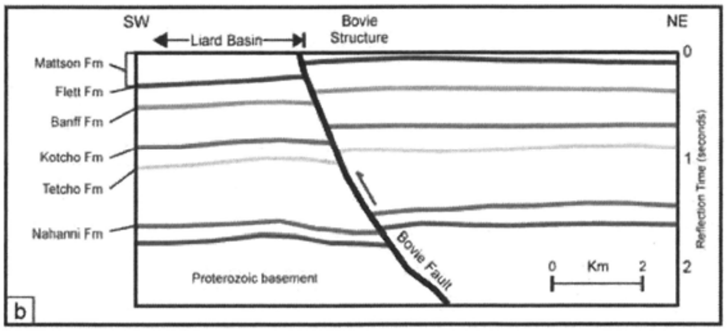


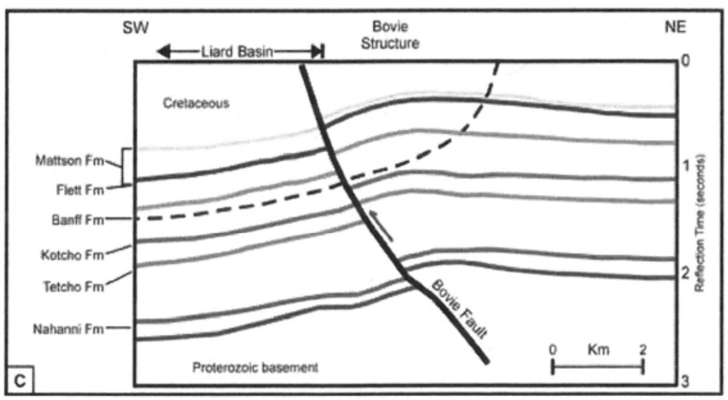
Figure 2. Schematic stratigraphic cross-section, showing transition of Mississippian carbonate platform westward and northward to basinal Prophet and Besa River formations (carbonate platform nomenclature from outcrop in Northwest Territories) (from Richards, 1989).



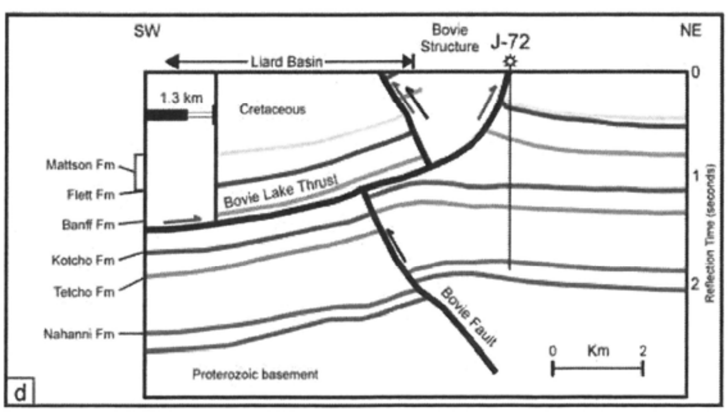
Early Carboniferous: There is neither evidence of Bovie Structure nor Liard Basin on this figure generated by flattening the seismic section on the top of Banff Formation reflection.



Early Cretaceous: Flattening on the base-Cretaceous unconformity reveals the first phase of Bovie Structure identifiable within the Central zone. The eastern flank of Liard Basin is defined by the abrupt change in Mattson Formation thickness caused by differential erosion across Bovie Fault. Uplift occurred pre-Cretaceous but post-Mattson, possibly coincident with uplift of the nearby Celibeta High.



Late? Cretaceous: Bovie Fault has been reactivated, possibly as a consequence of stresses imposed during the earliest Laramide. The dashed line marks the yet to be established shallow décollement Bovie Lake Thrust.



Laramide Orogeny: Bovie Lake Thrust has been established as a shallow décollement in the upper Banff Formation and has 'decapitated' the hanging-wall block of Bovie Fault. Horizontal translation of about 1.3 km, combined with reactivation of the decapitated portion of the older thrust, has produced today's subsurface and surface configurations.

Figure 3. Development of Bovie Fault Zone through time, illustrating structural complexity (from McLean and Morrow, 2004).

Overlying the pre-Cretaceous unconformity is the basal Chinkeh sandstone, succeeded by Cretaceous shales, themselves punctuated by widespread, generally low-quality sandstones of the Scatter and Sikanni formations (Fig. 3a).

The focus of this report will be on the Debolt/Rundle carbonate ramp/platform, which is the principal aquifer unit within the Horn River Basin. We will also address basal Cretaceous sandstones and the Mattson Formation, which provide more local aquifer capacity.

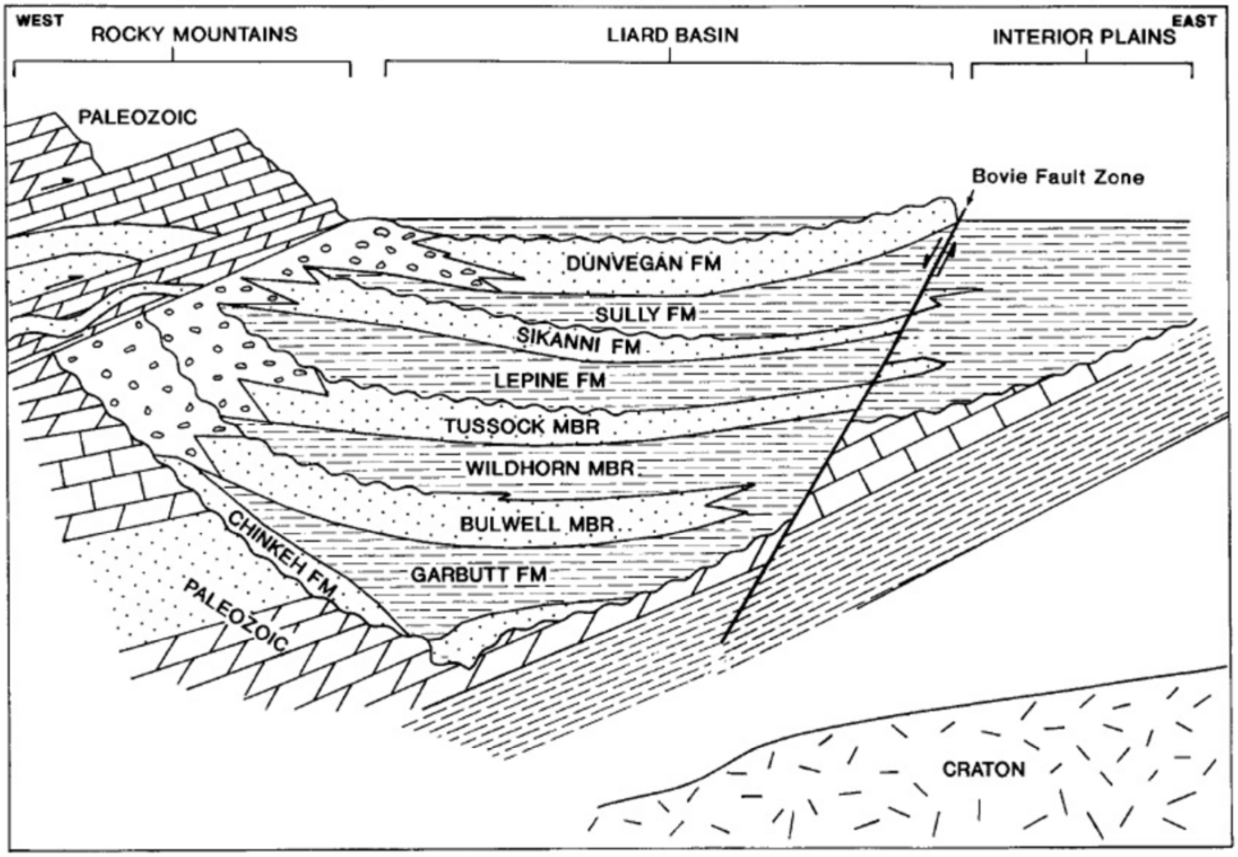


Figure 3a. Schematic cross-section across the Liard Basin (from Leckie et al., 1991). Focus is on the Cretaceous section; note that Mississippian through Triassic relationships are not accurately depicted.

METHODOLOGY

Stratigraphic mapping and reservoir characterization were supported by interpretation of well logs, cores, sample cuttings, and well test data. The Horn River Basin well database comprises all available wells penetrating the pre-Cretaceous unconformity in the study area, 556 in total, including 43 wells confidential at the time of the study, but released to the study group by HRBPG members. Many additional wells in the southeastern part of the basin were drilled to develop Jean Marie gas, and were not logged across the intervals of interest – and so are not included in our database or mapping.

To establish a stratigraphic framework, we built 16 regional cross-sections (Map 1), which are included with this study. Correlations were established from the literature and previous studies, and were calibrated with observations from cores and sample cuttings (described below). Logs from each well were tied to the cross-section grid to interpret stratigraphic tops, which were entered into a master stratigraphic database (Appendix V).

Cores were logged from 60 wells – we examined all cores that appeared to provide significant reservoir or stratigraphic information, omitting only a few short carbonate cores to the east and several Cretaceous sand/shale cores to the west.

Very few cores were cut in Mississippian carbonates within the Horn River Basin proper, and there is essentially no representation of the uppermost carbonate sections, which appear to have the best reservoir potential. Core coverage of Mattson reservoirs to the west is similarly scanty. A project was therefore commissioned, to systematically examine and document drill cuttings from Mississippian carbonates throughout the HRB, and from Mattson sandstone sections near HRBPG lands in the west. Sixty-three (63) wells were identified for the study by Producer Group members. John Clow (JC Consulting Inc.) examined cuttings across the prospective section in each, and performed semi-quantitative estimates of reservoir porosity and permeability; his methodology is described in more detail in his report (Appendix X). Jim Stepic (JMS Geological Consulting) prepared samples for standard petrography, SEM imaging, and XRD analysis, to provide additional reservoir characterization information (Appendix Y).

Canadian Discovery Ltd. compiled well test data from public formation pressure and water chemistry databases, and also incorporated proprietary pressure, chemistry, and deliverability data provided by members of the HRBPG. Data were screened to ensure their validity, and the following maps were created:

- Hydraulic head
- Pressure over depth
- Available head

- Formation water chemistry
- H_2S chemistry
- Resource volumes

Permeability analyses were also completed, and used to estimate well deliverabilities.

Incorporating all these data and interpretations, PRCL produced regional maps of key stratigraphic surfaces and intervals throughout the aquifer section. Core and sample data were tied to logs to estimate reservoir quality, which was also systematically mapped. Finally, reservoir maps were combined with hydrogeological interpretations to generate a basin-scale aquifer characterization of each key unit.

Mississippian carbonates make up the most widespread subsurface aquifer system above the Devonian shale gas reservoirs in the Horn River Basin (Fig. 1), and are the primary focus of this study. Basal Cretaceous sandstones (including the Chinkeh of the Liard Basin) and the Mattson Formation exhibit local aquifer potential, and so are also be described and mapped.

Devonian carbonates (Slave Point / Sulphur Point / Keg River) exhibit excellent reservoir quality, but are not suitable aquifers because they are located around the basin margins, contain large gas reserves, and are relatively deep. The Upper Devonian Jean Marie carbonate shelf (Fig. 1) is relatively tight and regionally gas-charged. Upper Cretaceous Dunvegan sandstones and conglomerates occur only locally, and are generally shallow enough to occur behind surface casing in most wells. In the Liard Basin, Scatter and Sikanni sandstones are generally argillaceous and exhibit poor reservoir quality. None of these units will be addressed in this study.

Figure 4 is a stratigraphic column illustrating detailed Mississippian / Cretaceous stratigraphy of the Horn River Basin, developed from correlations generated on our regional grid of stratigraphic cross-sections. Stratigraphic subdivisions are based upon log markers, which are tied to stratigraphy to the southeast documented in PRCL's regional Bivouac study (PRCL, 2000). While the Banff, Pekisko, and Debolt can be correlated with confidence to the southeast, the Shunda and Elkton of northwestern Alberta cannot be carried with confidence northward; thus, we use the more generic term "Rundle" for the equivalent part of the succession, and subdivide it according to log markers recognized in the HRB area (see cross-sections). Richards (1989) carried Mississippian outcrop nomenclature into the subsurface north of the study area, but these names were not used in this study because they are not familiar to most industry geologists.

Upper Mississippian (Visean) Mattson sandstones are present in the Liard Basin to the west, but are truncated eastward within the Bovie Fault Zone, although the Mattson and underlying Flett (Debolt equivalent) crop out in the core of an anticline along the Bovie Fault Zone immediately south of the B.C./NWT border (Taylor and Stott, 1968). The Mattson has no equivalent in the Horn River Basin, but is approximately correlative with the Stoddart Group of the Peace River area.

The pre-Cretaceous unconformity bevels the Mississippian carbonate ramp/platform succession eastward, truncating the Debolt within the Horn River Basin, and the upper Rundle along its eastern margin (Fig. 4). A weathered, or "detrital" zone , is present everywhere beneath the unconformity – analogous to the detrital Deville member recognized in the same stratigraphic position in Alberta by Badgley (1952) and others. Above the unconformity, Gething strata fill valleys incised primarily along the eastern

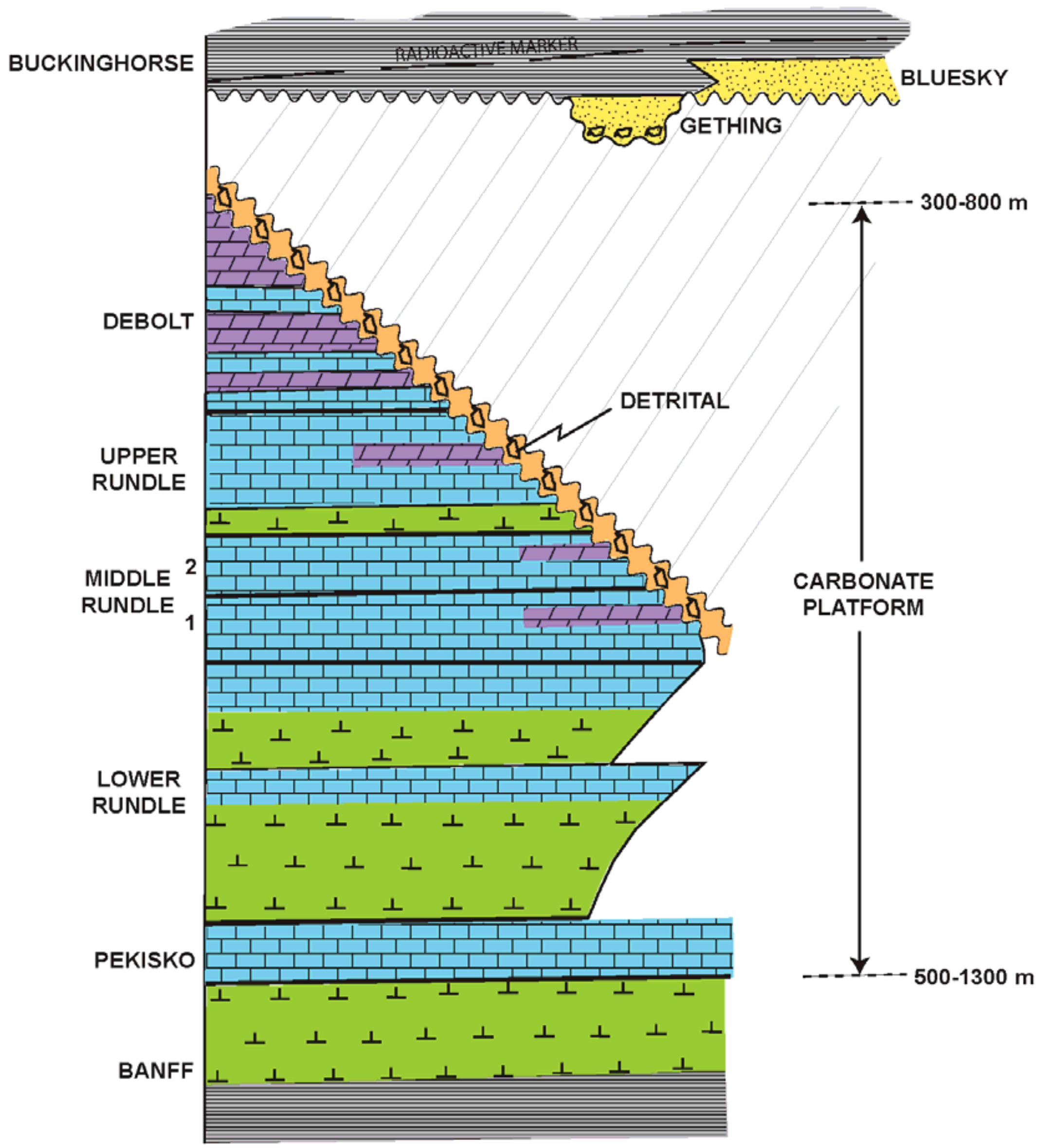


Figure 4. Stratigraphic column, Mississippian and Cretaceous section, Horn River Basin.

flank of the basin, and Bluesky shoreface sandstones occur along its southern flank. These names are assigned based on general stratigraphic position and depositional setting; no direct correlation is implied to their type sections far to the south. Basal Cretaceous Chinkeh sandstones in the Liard Basin have been described in outcrop and the subsurface in the west (Fig. 4a).

Map 5 is an isopach map from the pre-Cretaceous unconformity down to the top of the Banff, depicting thickness of the Mississippian carbonate package over most of the Horn River Basin. Triassic and Golata/Mattson/Fantasque sections are included in the southwest, and west of the Bovie Fault Zone. Note the general westward thickening, reflecting bevelling of the carbonate succession eastward beneath the pre-Cretaceous unconformity.

Finally, thick Cretaceous Buckinghorse shales blanket the entire succession and form bedrock across most of the Basin. A highly radioactive gamma-ray marker near the base has been documented regionally by Stott (1982), and serves as a definitive stratigraphic datum for the study.

Below, we review individual stratigraphic units in more detail.

Banff Formation

The Banff Formation is recognized throughout western Canada as a basinal to slope assemblage of shales and muddy limestones, arranged in stacked shallowing-upward successions (Richards *et al.*, 1994). PRCL (2000) mapped an “upper Banff clastic unit” as far north as eastern 94P, characterized by mixed siliciclastic/carbonate lithologies, and local development of porous siltstone reservoirs where the unit subcrops beneath the pre-Cretaceous unconformity.

In the Horn River Basin, no cores were available, but to the southeast, siltstones and tight nodular carbonates were observed in the upper Banff at c-77-G/94-I-14 (core log). Numerous wellsite strip logs show small amounts of siltstone in the upper 50-100 metres of the Banff, but calcareous shales and muddy distal carbonates predominate as the Banff shales out northwestward into Besa River shales (Fig. 2).

There is no reservoir / aquifer potential in the Banff Formation, and we have done no further work on it for this study.

Pekisko Formation

Where originally defined in south-central Alberta, the Pekisko Formation consists predominantly of clean transgressive grainstones, which appear on well logs as a blocky unit overlying the Banff, and underlying restricted marine and anhydritic Shunda lithologies (Richards, et al., 1994). PRCL (2000) recognized a blocky, relatively clean

Figure 4a. Chinkeh Kotaneelee Gap, Horn River Basin.

carbonate overlying the Banff as the Pekisko Formation, on the basis of its stratigraphic position and lithological and log characteristics, although it appears less distinct north of Twp. 112. Monahan (1999) correlated the Pekisko in the Liard Basin, and Richards (1989) recognized it in the Plains subsurface north of the NWT border.

In the Horn River Basin, we have correlated a relatively clean, blocky log interval, lying between Banff shales below and the shaly lower Rundle above, as the Pekisko. It correlates well to the Pekisko recognized by PRCL (2000), Monahan (1999), and Richards (1989). No cores were available in the study area, but wellsite log descriptions show it to be a tight, crystalline to somewhat argillaceous limestone. It thickens from about 5 metres in the southeast (Cross-section A-A') to 35 metres in the west and northwest (Cross-section D-D'). We regard the Pekisko primarily as a marker of the base of the Mississippian carbonate ramp/platform succession with no reservoir/aquifer potential, and as such, we did not spend much effort in precise definition of its boundaries.

Good reservoir quality in Pekisko limestones is observed generally along the subcrop edge, where dolomitization and solution has taken place – for example, at Haro in northwestern Alberta (PRCL, 2000) and Medicine River in west-central Alberta (Hopkins, 1999). As the Pekisko occurs more than 100 metres below the pre-Cretaceous unconformity throughout the Horn River Basin, no substantial reservoir quality was observed.

Rundle Group

Strata assigned to the Rundle (for the purposes of this study) make up the lower portion of the Mississippian carbonate ramp/platform succession, between the Pekisko below and the Debolt above. Shunda and Elkton subdivisions recognized further south, and surface-derived stratigraphy from the Yukon/NWT, cannot be carried with confidence into the Horn River Basin. We therefore subdivided the Rundle using log markers that can be carried across the HRB, and that appear to have significance as depositional units (see regional Cross-sections).

Regionally, the Rundle is recognized as the product of stacked transgressive/regressive cycles, with deposition occurring in outer ramp through marine shelf to intertidal environments (Richards et al., 1994; Richards, 1989; PRCL, 2000). Each cycle prograded northward and westward toward the Besa River shale basin (Fig. 2). To the south, PRCL documented cycles culminating in open marine to restricted facies, while to the north, Richards (1989) interpreted more distal slope to shelfal facies through most of the succession. HRB regional log markers are picked at the top of apparent shoaling-upward cycles, and correspond to transgressive surfaces Overall, the Rundle package appears to become cleaner and more proximal upward - thick shale intervals and pronounced cyclicity are evident in the lower Rundle, while the upper Rundle is dominated by cleaner carbonates with little evidence of well-developed transgressive surfaces.

Most HRB-area cores logged are too short to document depositional cycles, but a few longer sections (e.g., d-84-K/94-P-6, d-14-I/94-P-12, d-97-C/94-P-13, and d-33-E/94-P-13) demonstrate shoaling-upward cycles capped by shallow marine packstones with poor to moderate reservoir quality (Fig. R1-R3). Facies variations can be subtle, and in some cases, it is difficult to match regional log markers with transgressive surfaces in core.

In sample cuttings, a variety of grain sizes and textures are evident, from carbonate mudstones through very finely crystalline limestones to wackestones and grainstones, with bioclastic materials composed primarily of crinoids, with common corals and bivalves (Appendix X). Limestones dominate throughout, although dolomitized carbonates and leached cherts that appear to be weathering ("detrital") remnants are common at the top of the carbonate platform in many wells (see Appendix Y for a more detailed petrographic review). Flooding intervals and shoaling-upward cycles are evident in samples, where sample quality is good. Thin sections show poor reservoir quality in limestones to be a product of blocky spar calcite cement and significant micritic matrix. Locally (e.g., cuttings logs b-6-G/94-O-7; c-A68-B/94-O-15) we see dolomite occur deeper in the platform, apparently disconnected from the capping unconformity (Figs. R4, R5).

We have not mapped the lower Rundle separately, as it has not developed significant reservoir quality in the Horn River Basin.

Middle Rundle strata are 30-40 metres thick across much of the Basin, thickening to >50 metres in the northwest (Map 6). Pre-Cretaceous erosion bevels the unit along the eastern margin, although the zero edge lies east of the study area. In the far west and into the Liard Basin, we can no longer distinguish the informal Rundle units, and so equivalents to the west are grouped as "undifferentiated Rundle".

The upper Rundle exhibits pre-Cretaceous erosion more dramatically, thinning from >100 metres in the west to a zero edge in the northeast (Map 7). Relief along the eastern margin reflects valley incision on the unconformity, and we see that porous Gething sands filling the valleys lie directly on the middle and upper Rundle surfaces.

Pools to the east and southeast (Thetlaandoa, Desan, Kotcho, Sierra) of the HRB produce oil and gas from moderate-quality reservoirs in relatively proximal packstone/grainstone facies at the top of individual cycles within the Rundle, particularly along subcrop edges where reservoir quality may be diagenetically enhanced. Within the Horn River Basin, Rundle facies are generally somewhat muddier and/or more cemented, and hence exhibit very limited porosity and permeability. Core analysis and sample cuttings estimations exhibit porosities generally less than 5%, and permeabilities less than 0.5 mD (Appendix X, Y). Much better reservoir quality is associated with the capping dolomitized / leached ("detrital") interval, which is discussed below.

Figure R1. Massive, very coarse-grained crinoidal limestone (grainstone/packstone), oil-stained. Mobil North Petitot d-97-C/94-P-13, 362.5 m (Ø 11.6%, K 0.03 mD).

Figure R2. Massive, well-sorted and compacted coarse crinoidal limestone (packstone/grainstone), planar-bedded. Wincan et al Kimea d-57-D/94-P-10, 439 m (Ø 7.7%, K 2.3 mD).

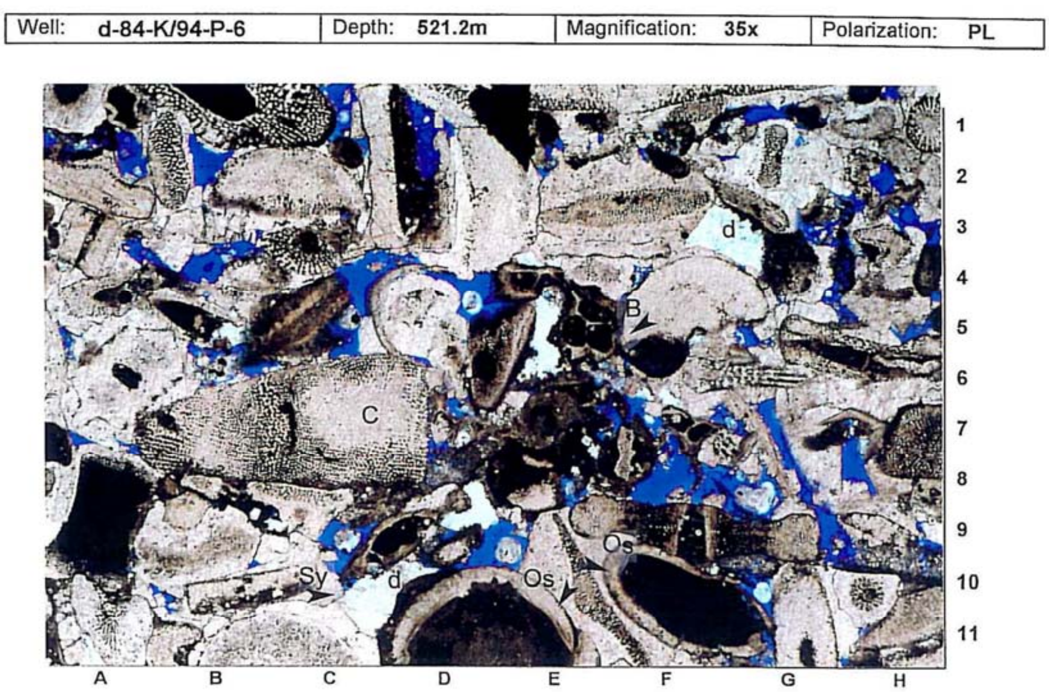


Figure R3. Crinoid-rich grainstone with accessory bryozoans and ostracods. Leaching of syntaxial calcite cement gives fair porosity; minor dolomite also present. Canterra et al Thetlaandoa d-84-K/94-P-6, 521.2 m (Core analysis Ø 6.5%, K 0.26 mD).

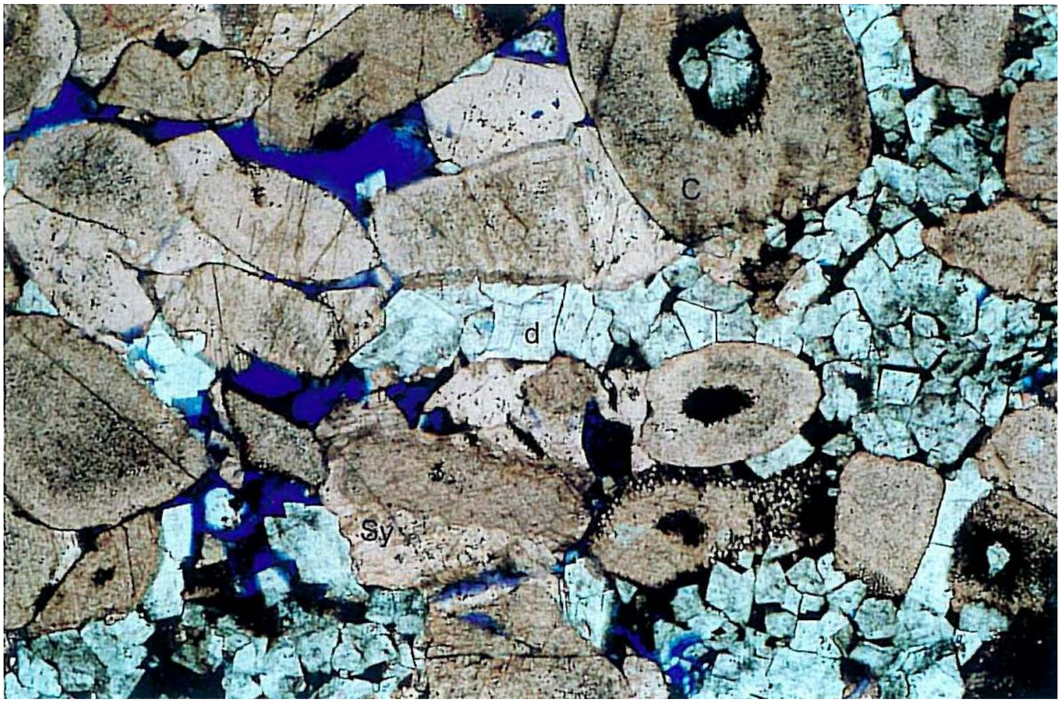


Figure R4: Partly dolomitized coarse-grained crinoidal grainstone. Dolomite (d) is an early-stage cement, followed by syntaxial calcite cement (sy). Gulf AEC Desan d-41-D/94-P-7, 640.1 m, (Core analysis Ø 5.3%, K 4.9 mD)

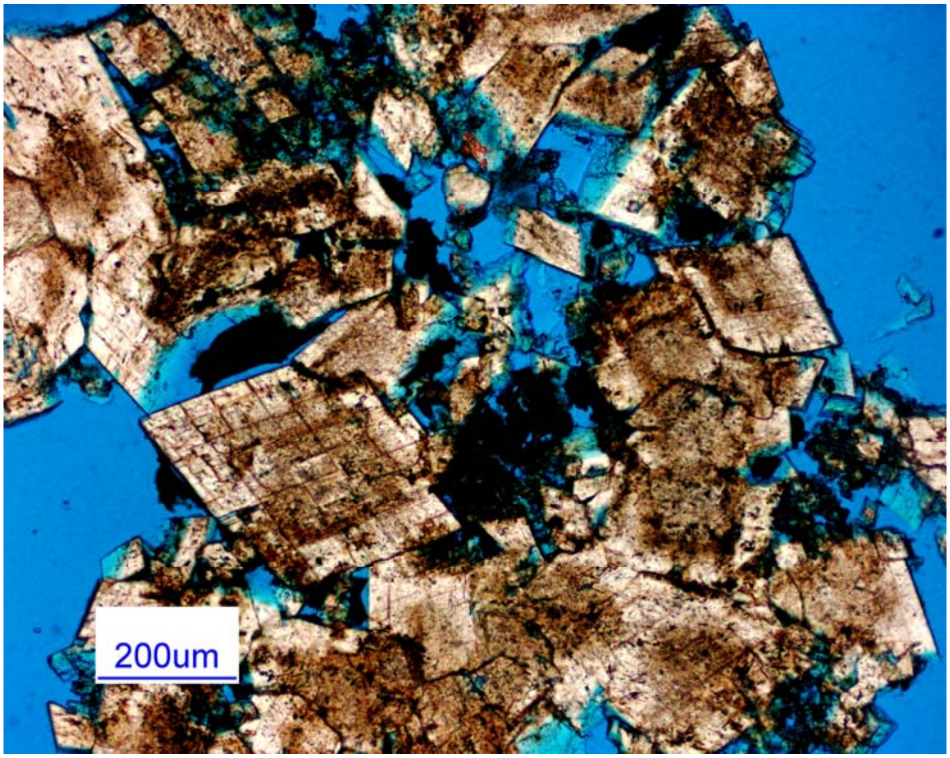


Figure R5. Extensively dolomitized upper Rundle section, approximately 100 metres below pre-Cretaceous unconformity. BA Pan Am Playmate b-6-G/94-O-7, 2180 ft.

Debolt Formation

The term “Debolt” is commonly used to refer to the entire Mississippian carbonate ramp/platform succession in the Horn River Basin, but in this study, we see only the upper part of the succession as correlative to the Debolt of northwestern Alberta. A highly-persistent flooding surface separates blocky clean carbonates of the upper Rundle from clean carbonates of the Debolt (see regional Cross-sections).

We interpret the same progradational carbonate ramp / platform depositional setting for the Debolt as for the Rundle, based on regional correlations and core descriptions to the south (PRCL, 2000). Only six Debolt cores were found in the study area, all in the far southwest:

- c-94-L/94-J-9
- a-19-G/94-J-10
- 02/a-65-G/94-J-10
- c-64-I/94-J-10
- d-83-I/94-J-10
- b-6-A/94-J-16

All of these were cut at or very close to the pre-Cretaceous unconformity, and all exhibit fracturing and rubbling (Fig. Db1). Four of the six cores are only 10-20 feet long, leading us to believe that core recovery was poor, probably as a result of fracturing. Dolomudstones and wackestones appear to dominate, although these facies may be over-represented, considering the fractional recovery.

Sample cuttings show a range of limestone and carbonate mudstone lithologies similar to those observed in the Rundle (Appendix X, Y). Modest reservoir quality is developed in clean limestone facies in isolated intervals (e.g., 820-830 m, b-91-B/94-O-10), but these rocks are generally tight. Dolomitized and leached intervals at the top of the Debolt, immediately underlying the pre-Cretaceous unconformity, are well-developed in many areas, particularly near the eastern subcrop edge of the Debolt (see discussion below).

The Debolt isopach map (Map 8) demonstrates dramatic eastward bevelling beneath the pre-Cretaceous unconformity, as we see relatively rapid thinning to a north-south zero edge through most of the basin, turning to an east-west orientation along the southern margin. Westward, the Debolt is grouped within the “undifferentiated Rundle”, as detailed log correlations cannot be made with confidence.

Reservoir quality in Debolt limestones is generally poor, comparable to that described above for the Rundle. Regional hydrogeological mapping by PRCL (2000) showed abundant potential for Debolt gas reservoir1s immediately southeast of the Horn River Basin, In Kotcho and surrounding areas. Recent drilling in those areas has

Figure Db1. Fractured upper Debolt, with white sparry calcite cement filling fractures. Gulf States Imperial Clarke Lake c-64-I/94-J-10, 1810 ft.

demonstrated good to excellent reservoir quality at the top of the formation, equivalent to the upper dolomitized / leached "detrital" interval described below.

"Detrital" Zone

Sample cuttings and limited core illustrate the widespread presence of an intensively leached and dolomitized zone ("detrital zone") at or near the top of the Mississippian carbonate platform (see, in particular, cuttings logs from wells in 94-O-8). Very finely crystalline to coarse crystalline dolomites exhibit common sucrosic texture, and pinpoint to large vuggy pores with drusy dolomite lining (Fig. D1, D2) (see Appendix Y for a more detailed petrographic review). Leached cherts are also common, probably representing the remant silicified carbonates (Fig. D3). Evidence of fractures is also seen in some places.

Clow estimated dolomite porosities ranging in excess of 10%, and his permeability estimates range from several millidarcies to the Darcy range (Appendix X). Note, however, that accurate quantitative estimates are very difficult at these higher levels. Well logs rarely reflect these lithologies and reservoir qualities accurately, as hole conditions are generally quite poor across the "detrital zone". In many cases, all we can see on logs is an interval of irregular or off-scale responses, which we interpret as the "detrital zone" on the basis of stratigraphic position.

Stepic estimated similar reservoir quality in most dolomite / "detrital zone" samples, and interpreted their origin as low-temperature mixing zone conditions (reflux dolomitization), possibly related to exposure and karsting (Appendix Y). Locally, however, dolomite occurs as tightly interlocking crystals with curved crystal faces – interpreted as having a hydrothermal origin. The latter dolomites are more likely to be associated with fluid flow along fractures or faults.

Reservoir quality in chert-rich "detrital zone" facies is generally poor, with local modest reservoir development associated with intercrystalline and vuggy porosity.

Few adverse reactions between introduced fluids and "detrital zone" or unaltered Mississippian carbonate strata are to be expected, as water-sensitive clays and pore-plugging bitumen were generally not observed (Appendix Y).

Development of a "detrital zone" associated with a profound unconformity on carbonate substrate is common in the subsurface of western North America. Excellent outcrop analogues occur on the flanks of the Little Belt Mountains in northern Montana (Fig. D4-D6). Here, extensive solution has destroyed bedding through collapse (Fig. D4). Brecciation, dolomitization, extensive porosity development, and recrystallization are evident in these beds (Fig. D5-D6). Regional fracture systems are also present in the upper Madison ramp/shelf, and feed up to 700,000 m^3/d of water into the Giant Springs at Great Falls, Montana, on the banks of the Missouri River (Fig. D7).

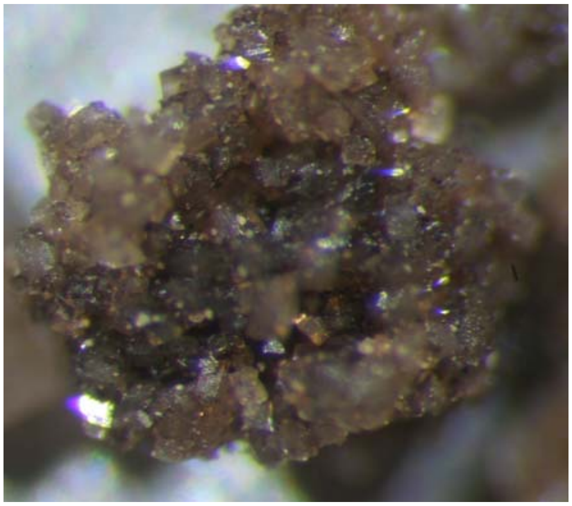


Figure D1. Sample cutting from Debolt "detrital zone", showing good porosity development in sucrosic dolomite. Paramount Komie b-86-K/94-O-1, 505 m.

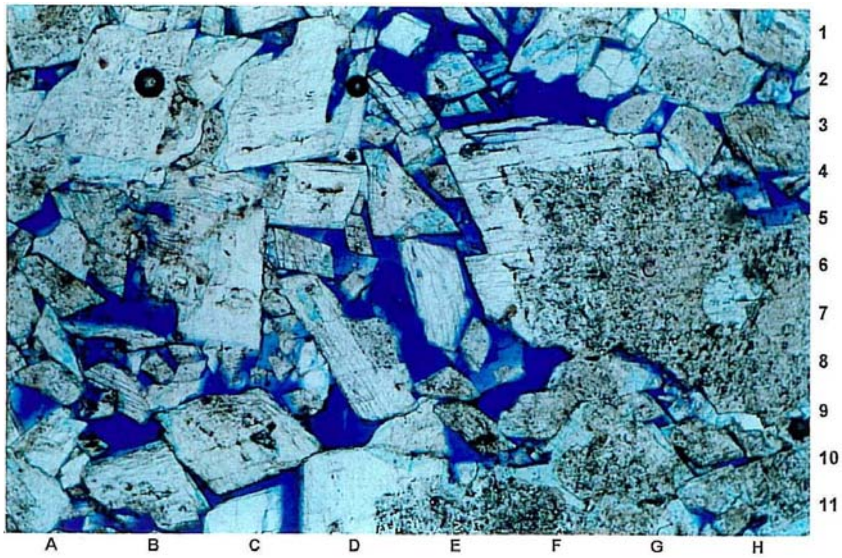


Figure D2. Sucrosic dolomite in upper Rundle "detrital zone", showing excellent enlarged inter-crystalline porosity; note crinoid ghost (c). Texex et al. Tsea c-48-K/94-P-5, 1992.2 ft (Core analysis Ø 14.3%, K 18 mD).

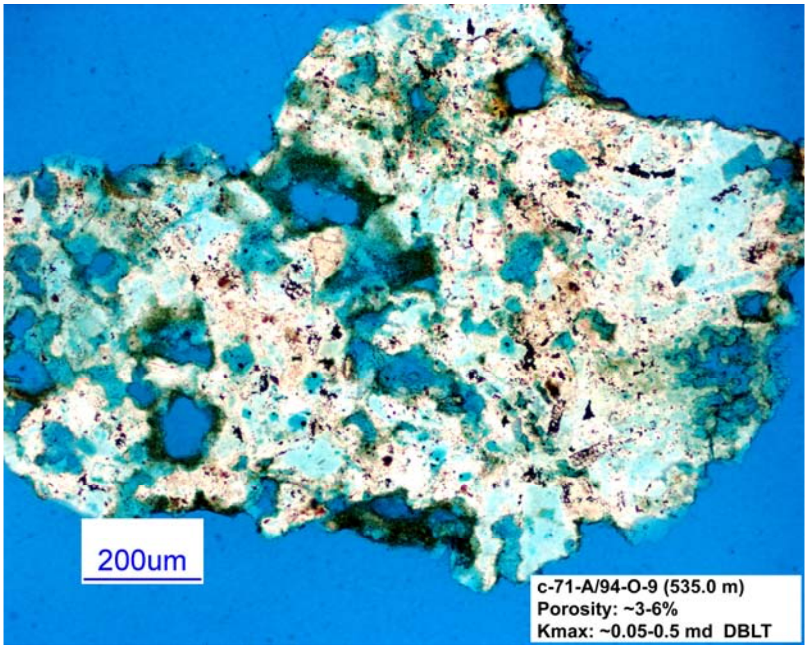


Figure D3. Leached silicified carbonate from Debolt "detrital zone". Apache Missile c-71-A/94-O-9, 535 m.

Figure D4. Flat-lying Mississippian (Madison Fm) carbonate ramp/shelf deposits, northern Montana Little Belt Mountains. Bedding has been destroyed by collapse resulting from solution of underlying strata.

Figure D5. Solution breccia exhibiting excellent inter-clast porosity with drusy pore-lining cements. Madison Formation, northern Montana near Little Belt Mountains.

Figure D6. Madison solution breccia, as above.

Figure D7. Water flowing from fractures at Giant Springs, Montana, into the Missouri River. Regional fractures are visible in opposite river bank beneath building.

There are well-developed, porous dolomites deeper in the Debolt / Rundle section in places, tens to one hundred metres (plus) below the pre-Cretaceous unconformity (e.g., cuttings log b-6-G/94-O-7). We speculate that these may be related to dolomitizing fluids introduced by local faults. Additional work might be done to characterize these dolomites, to see whether they might be the product of hydrothermal dolomitization.

Mattson Formation

The Mattson was originally described in outcrop, and surface exposures were correlated over an area of southeastern Yukon, southwestern Northwest Territories, and northernmost B.C., in a series of Geological Survey of Canada reports in the 1950's and 1960's. Within the study area, about 300 feet of Mattson sandstone crops out in the Bovie Anticline, on the eastern margin of the Bovie Fault Zone, but has not been described in detail (Taylor and Stott, 1968). Little subsurface work has been published with the exception of Monahan (1999), who presented a series of well-log cross-sections in the Liard Basin, and a brief discussion.

At the type section at Jackfish Gap (Fig. M1), the Mattson consists of coarsening- and sandier-upward prodeltaic fine clastics, overlain by deltaic to fluvial and floodplain strata. Regional outcrop mapping establishes a deltaic depocentre in the vicinity of the type section. Southward and westward of the Horn River Basin, the Mattson grades to prodeltaic and fine-grained marine strata; further westward, it grades into basinal Besa River shales.

Map 10 shows Mattson strata thickening abruptly westward from the Bovie Fault Zone to a thickness of 600 metres. Well control is not sufficient to break out clear subunits or depositional trends with this area, but clean, thick, reservoir-quality sandstones occur in a number of wells (e.g., core log d-87-A/94-O-11). Sandstones are generally very fine- to fine-grained, massive to low-angle cross-bedded in metre-scale sets, broken by thin grey to green shale beds (Fig. M2). Mud clasts and shell debris (or moldic porosity after shell fragments) are locally common, and minor burrowing suggests some marine / deltaic influence (Fig. M3).

Mattson sandstones are typically quartzarenites; minor framework components include chert, phosphate, and detrital carbonate grains (Appendix Y). Silica is the primary cement, mostly in the form of quartz overgrowths. Carbonate cements are highly variable, ranging from absent to porosity-occlusive (e.g., core log c-37-G/94-O-6). Kaolinite cement is common in finer (silt-sized) rock. Pyrobitumen occludes porosity in core at b-21-K/94-O-14 and a-28-D/94-O-15 (Fig. M4), and was described in a few wellsite cuttings reports from wells near the NWT border. Little bitumen was seen in cuttings logged for this study, however, and must be regarded as being important only locally. Where fossil fragments are heavily concentrated, sandstones may take on a bioclastic texture (Fig. M5).

Figure M1. Type section, Mattson Formation, at Jackfish Gap in southern Yukon Territory. Tan-coloured, sand-dominatedMattson strata lie on grey Golata and Flett (Mississippian carbonate equivalent) units

Figure M2. Fine-grained, massive to planar-bedded Mattson sandstones with platy green-grey shale bed. Hess Aquitaine et al Windflower d-67-A/94-O-11.

Figure M3. Very fine-grained sandstone with large vertical Diplocraterion burrow. Aquitaine et al. Tattoo a-78-L/94-O-10, 2470 ft.

Figure M4. Sandstone, fine-grained, with pervasive pyrobitumen. Thin, flat mudstone rip-up clasts are not stained. ARCO Maxhamish b-21-K/94-O-14, 5375 ft.

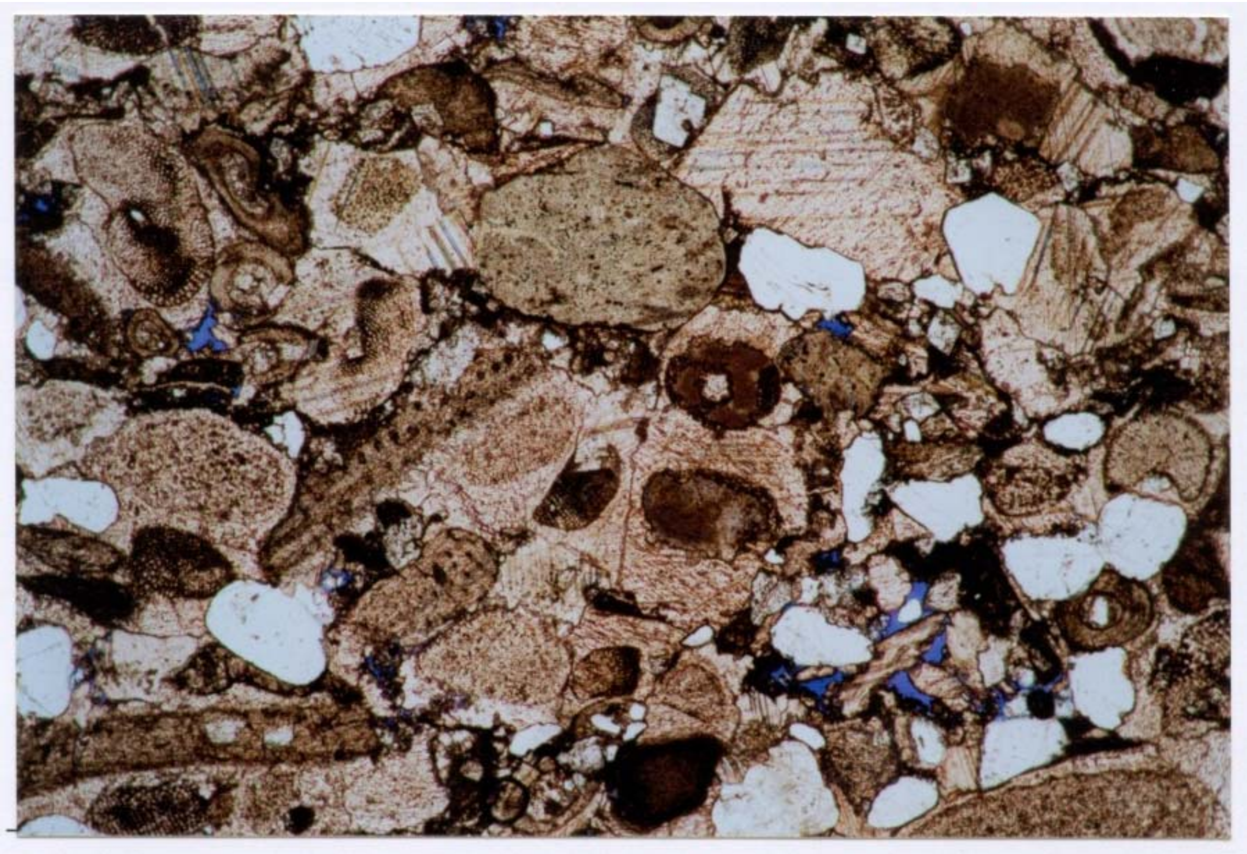


Figure M5. Sandy limestone – originally bioclastic grainstone with minor quartzose sand. Bioclasts include abundant echinoderms and brachiopod shell fragments. Ammin Aquitaine et al. Windflower d-6-H/94-O-11, 1417.7 ft.

Reservoir quality ranges from very poor in very fine-grained rocks and tightly-cemented sandstones to excellent in well-sorted quartz sandstones (Fig. M6). Porosities locally exceed 20%, and permeabilities range into the hundreds of millidarcies (see core analysis plots on core logs). Most porosity is primarily intergranular, augmented by secondary solution of chert and carbonate grains. In the Windflower gas field (Fig. M7), average porosity is listed at 15%.

Sample cuttings logs (e.g., c-66-E/94-O-10, b-96-E/94-O-10, a-27-L/94-O-10) document longer sand-dominated, variably-cemented Mattson sections.

Natural fracturing was observed in several cores, particularly in more tightly-cemented intervals, and is likely related to tectonic activity along the Bovie Fault Zone.

Cretaceous Sandstones

Sandstones lying directly on the pre-Cretaceous unconformity are mapped on the eastern, southern, and western flanks of the Horn River Basin (Map 11). Each appears to be the product of different depositional events, and we regard each as a separate unit.

Gething Formation

Gething strata are patchily distributed on the eastern flank of the HRB, ranging up to 25 metres thick (Map 11). Scour-based, sand-dominated fining-upward successions occur in thicker sections (core log d-33-E/94-P-13, d-33-F/94-P-13). (Cross-section I-I’). Thin coarsening-upward successions (tentatively assigned to the Bluesky) can be distinguished where there is core, and/or log quality is good, but cannot be mapped with certainty.

Gething sandstones reach medium to coarse grain size, and are dominated by quartz, with variable proportions of chert and sedimentary rock fragments (Fig. G1, G2). Large clasts of fresh unweathered carbonates were noted in places, implying significant relief on a channel wall or escarpment composed of Mississippian carbonates (Fig. G3, G4).

We interpret Gething deposition to have occurred in a south to north valley system which cut into the Mississippian carbonate platform, and controlled the north-south subcrop edge of the Debolt Formation (Map 8). In some wells with no core/sample control, distinguishing between the Gething and a “detrital zone” section can be very difficult, and in reality, there is no absolute dividing line between the two units. Thus, some stratigraphic assignments, particularly along the western valley margin, are questionable, and there may be some inconsistencies between closely-spaced wells. The eastern edge of the valley is not well defined by the well control in this study, but PRCL (2000) mapped only scattered evidence of valley-fill deposition further east. The

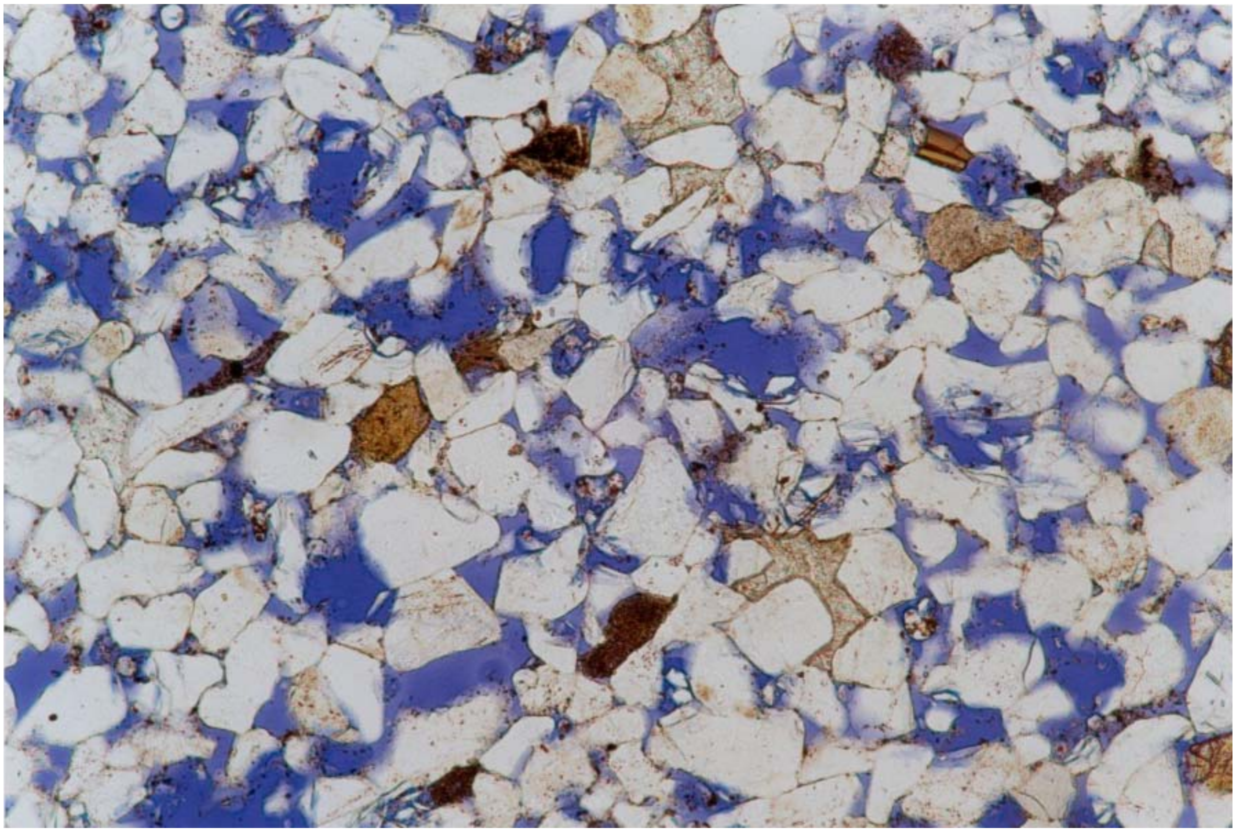


Figure M6: Moderately-sorted quartzarenite with minor dolomite cement. Excellent reservoir quality (~25%). Ammin Aquitaine et al Windflower d-6-H/94-O-11, 1581 ft.

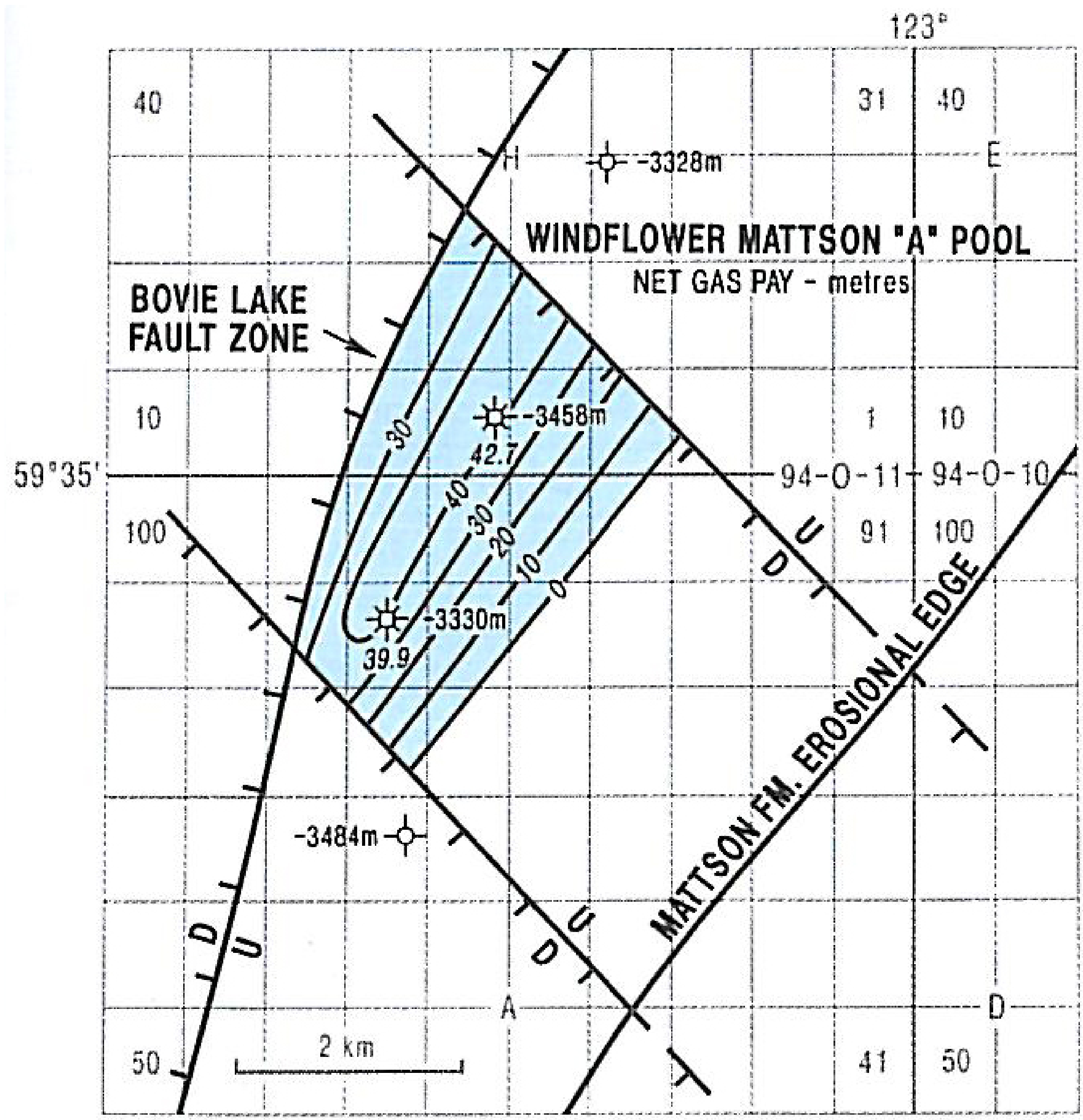


Figure M7: Windflower Mattson gas pool – gas is trapped in thick Mattson sandstones in a structural trap associated with the Bovie Fault Zone (from Barclay et al., 1997)

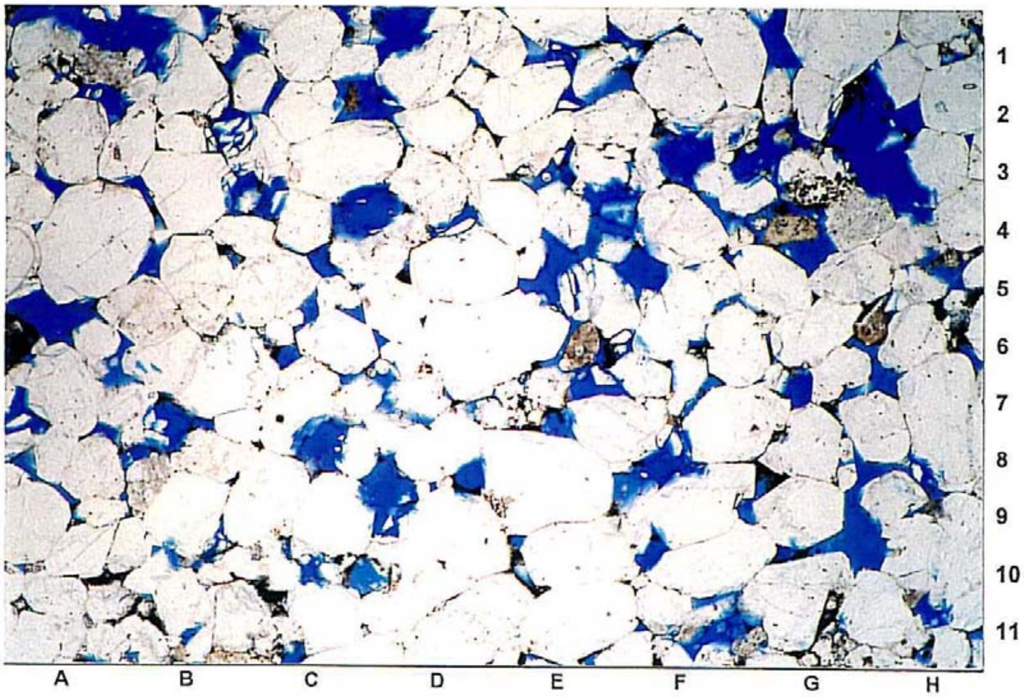


Figure G1. Medium- to coarse-grained, moderately-sorted quartz arenite, exhibiting some well-developed quartz overgrowths. Mobil North Petitot d-33-E/94-P-13, 298.1 m (Core analysis Ø 21.6%, K 311 mD).

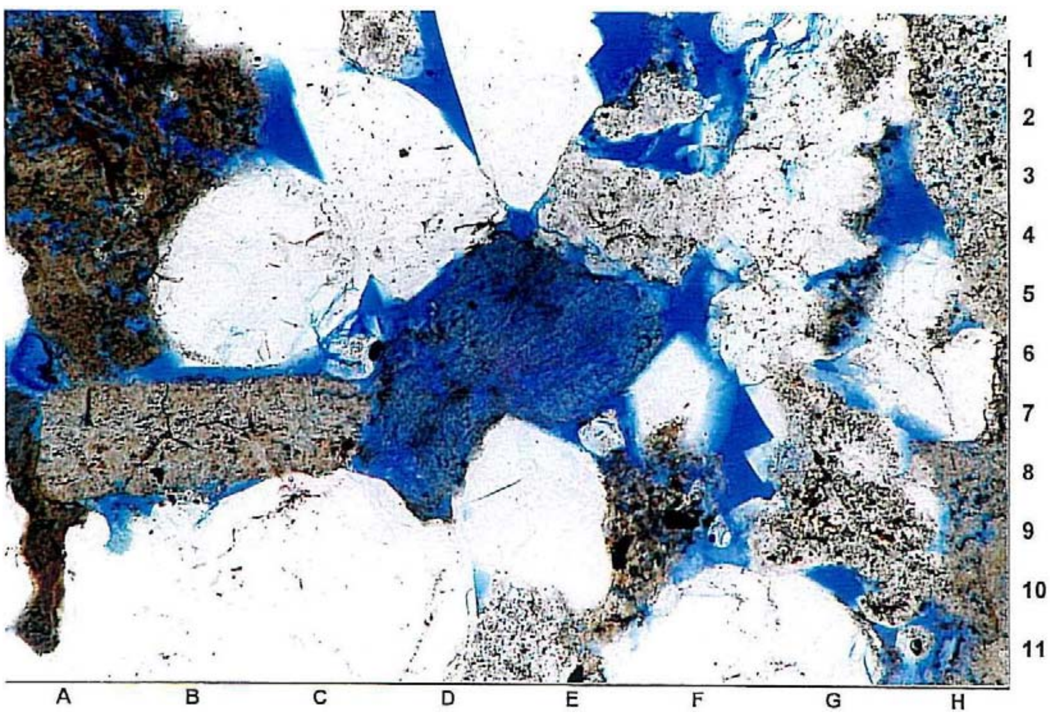


Figure G2. Good secondary porosity development through dissolution of argillaceous rock fragments and chert. UCEL Hossitl d-100-J/94-P-14, 556.5 m (Core analysis Ø 19.9%, K 906 mD).

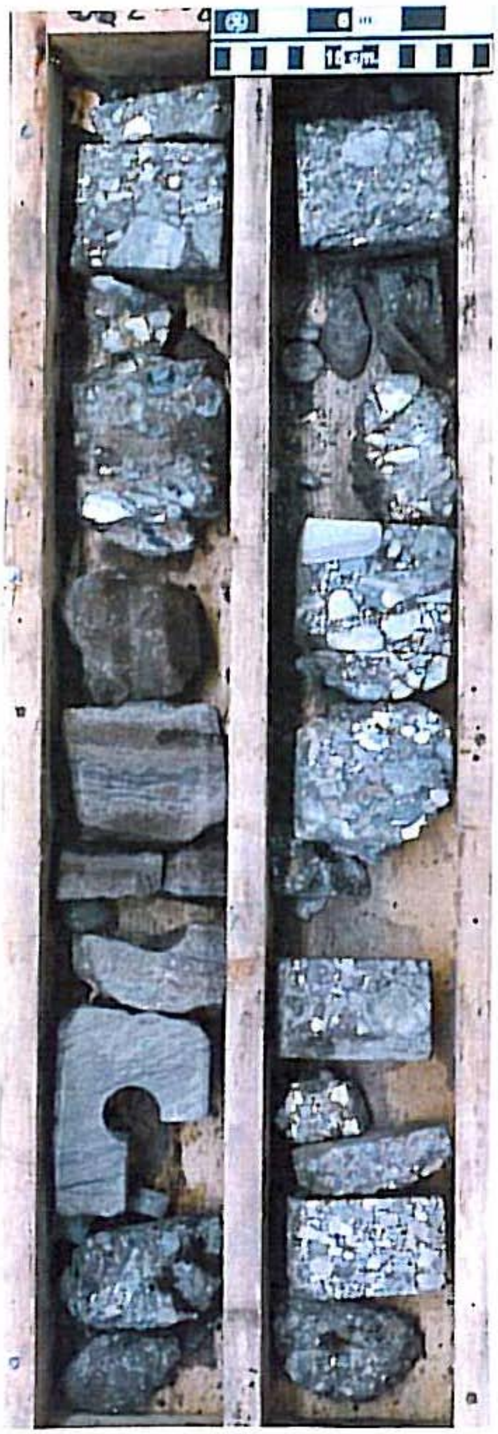


Figure G3. Interbedded poorly-sorted Gething conglomerate with sandstone matrix, and argillaceous sandstone. Mobil North Petitot d-33-E/94-P-13, 298-299.2 m (Core analysis Ø 14-22%, K 44-396 mD).

Figure G4. Large dolostone clast within Gething conglomerate, indicative of nearby incision and transport of Mississippian (Debolt) carbonates. Mobil North Petitot d-33-F/94-P-13, 331 m.

PRCL study also demonstrated a major southwest-northeast trending drainage divide through 94-P-4 (not evident on Map 11 as it is partially transgressed by Bluesky sands), separating the HRB Gething valley system from more regional, southerly-draining valleys to the south.

Bluesky Formation

Bluesky sandstones and siltstones were deposited along a continuous east-west trend on the southern flank of the Horn River Basin, ranging in excess of 20 metres (Map 11). Clean, porous proximal shoreface sandstones dominate in the southeast (core log b-68-H/94-I-14; Fig. B1), but grade to silty, more distal shoreface successions westward (core log a-8-B/94-I-13, c-40-K/94-I-12; Fig. B2), which eventually either pinch out or lose character within regional Buckinghorse shales (Cross-section B-B').

Where the Bluesky is optimally developed, it is composed of very fine-grained quartz sublitharenites, with accessory chert, rock fragments, and minor detrital carbonate grains, phosphate, and glauconite (Fig. B3). Reservoir quality is generally very good, with porosities ranging in excess of 25%, and permeabilities to hundreds of millidarcies. Westward, however, reservoir quality deteriorates markedly as heterolithic strata and argillaceous siltstones dominate the succession.

PRCL (2000) mapped extensive Bluesky shoreface deposits flanking major pre-Cretaceous highlands throughout eastern NEBC. The trend mapped in this study appears to be the distal reaches of the shoreface complex on the northern flank of the Keg River Highlands (Smith, 1994).

Chinkeh Formation

Sandstones and finer-grained clastics of the Chinkeh Formation were described and mapped in the Liard Basin and northward by Leckie et al. (1991) and Frank et al. (1999). Deposition took place in a variety of non-marine to marine settings, but the best reservoir quality appears to be in shoreface sandstones that are the primary reservoir in the Maxhamish Field, running north-south through the centre of 94-O-11 and 94-O-14 (Maxhamish wells are shown on regional maps, although only a few were used as control points).

Chinkeh sandstones are predominantly fine-grained quartz arenites to sublitharenites, featuring abundant accessory glauconite and clays. Porosities have been noted to range up to 20%, and permeabilities to tens of millidarcies in good reservoir rock. However, regional cross-sections and core logs through the Chinkeh in this study also demonstrate a high proportion of argillaceous, fine-grained, non-reservoir rock (e.g., core log b-98-A/94-O-5, 02/b-71-K/94-O-6; Fig. Ch1; Cross-section BI-BI').

Figure B1. Bluesky shoreface sandstone with prominent Cylindrichnus (Rosselia?) burrow. Cdn Reserve Quintana Kotcho b-68-H/94-I-14, 1964 ft. (Core analysis Ø 20.4%, K 32 mD).

Figure B2. Pervasively burrowed Bluesky distal shoreface sandstone/mudstone. Mobil Sahtaneh a-8-B/94-I-13, 616.5 m.

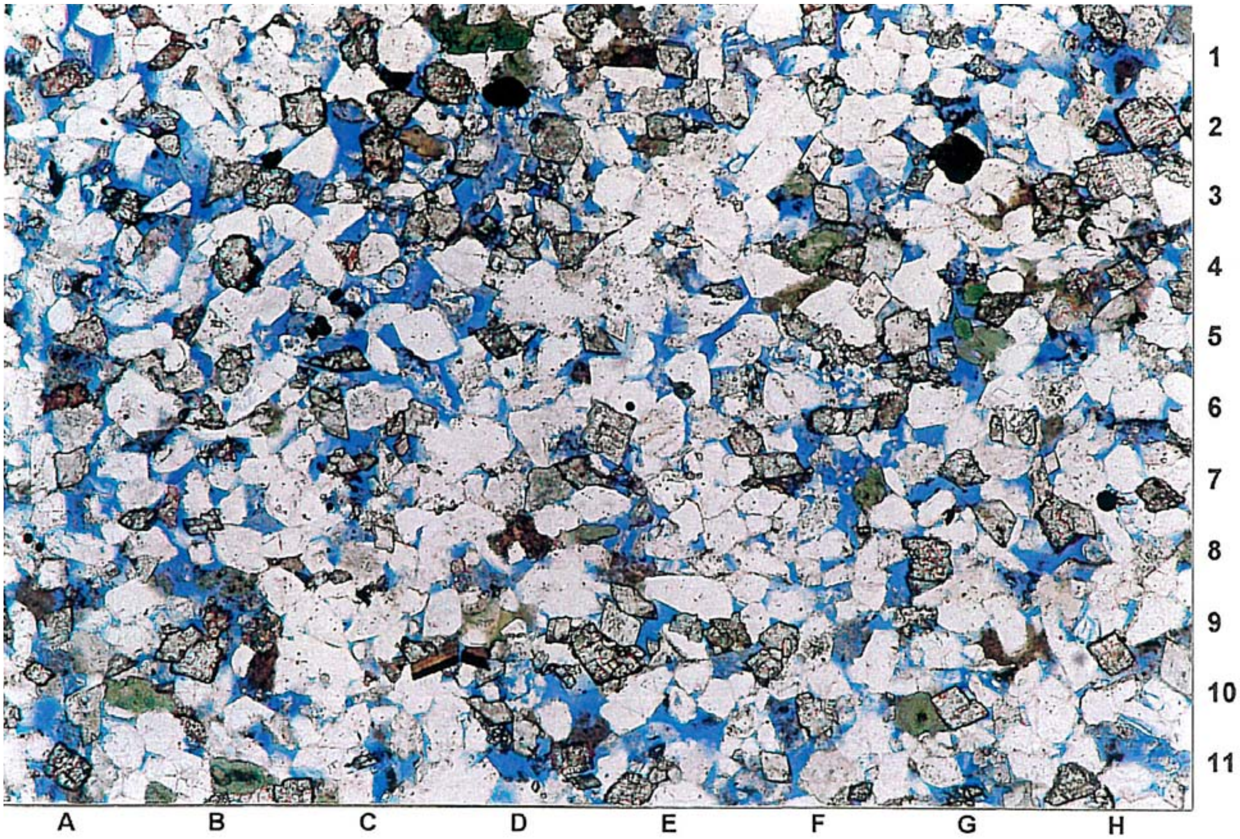


Figure B3. Very fine- to fine-grained , well-sorted quartz litharenite in Bluesky southeast of Horn River Basin. Dolomite occurs as detrital grains, overgrowths, and cement; glauconite grains scattered throughout. AEC Spruce d-86-L/94-I-9, 333.6 m (Core analysis Ø 24.2%, K 151 mD).

Figure Ch1. Variably argillaceous, rooted Chinkeh sandstones, exhibiting poor reservoir quality. EOG Maxhamish a-50-I/94-O-14.

A thick, clean, porous sandstone succession penetrated by several wells in I/94-O-14 and F, K, L/94-O-15 has been mapped as Chinkeh, although we believe some operators have assigned it to the Mattson. These sands are found in a structurally-disturbed area in the Bovie Fault Zone, immediately offsetting local surface exposures of the Mattson and Flett/Debolt (see Map 10). We considered the Mattson interpretation, but settled upon the Chinkeh interpretation because:

- Stratigraphic position is consistent with the Chinkeh – overlying the pre-Cretaceous unconformity
- Stratigraphic position is not consistent with the Mattson – lies on the Fantasque (and regional Mattson) in d-87-I/94-O-14, and directly on the Debolt (no intervening Golata) in c-20-K/94-O-15 (Cross-section BI-BI')
- The sandstone section appears very similar on logs from well to well, and ranges from 24 to 85 metres thick. The (typical) Mattson section at a-57-L/94-O-15, drilled very close to the Mattson outcrops, is in excess of 500 metres thick.
- Clean, porous, quartz-rich sandstones, logged in sample cuttings at 02/c-90-F/94-O-15 are consistent with Chinkeh shoreface sandstones (but could also be from the Mattson)

Detailed regional maps have not been published for the Chinkeh. Our well control is sufficient to show widespread but relatively thin Chinkeh sands limited to the western side of the Bovie Fault Zone, except for the areally-limited sand body discussed above (Map 11).

RESERVOIR QUALITY MAPPING

We have applied reservoir quality cutoffs to define and map net reservoir thickness for the main aquifer units. Simple regional cutoffs serve to outline major trends, and allow for comparisons among different areas. They also allow us to relate hydrogeological data to reservoir presence and continuity. Regional cutoffs are less reliable at a local scale, particularly as mineralogical and particle size reservoir controls cannot be fully assessed.

Rundle and Debolt / Detrital Zone

Reservoir quality mapping in Rundle / Debolt carbonates is focused on the dolomitized intervals within the platform, and in the capping "detrital zone". Porosity and permeability are too poor in the unaltered carbonates to be worth considering.

Highly variable mineralogy, irregular porosity distribution (intercrystalline, vuggy, fracture), and poor hole conditions make quantitative measurement of porosity from logs virtually impossible (Fig. RQ1). In fact, as noted above, assigning the weathered interval to the "detrital" vs the Gething is difficult in places, even with sample control. Porosity therefore was estimated in a semi-quantitative fashion, based firstly upon reservoir quality interpretations from sample cuttings:

- Excellent: highest-grade porosity, with permeabilities consistently > 50 mD
- Good: good porosity, with permeabilities up to 50 mD
- Poor: limited porosity, with permeabilities generally <1 mD

Log responses were calibrated against Clow sample logs to derive as good a relationship as possible between log response and rock quality.

Reliability of the reservoir quality assessment was graded according to the available evidence:

- Lithology control:
    - Good core coverage (best) (actually does not occur in the carbonates)
    - Clow sample log with good sample quality
    - Good wellsite sample log
    - Poor wellsite sample log
    - No lithological control (worst)

BRC HTR et al OOTLA
D-92-H/94-O-9

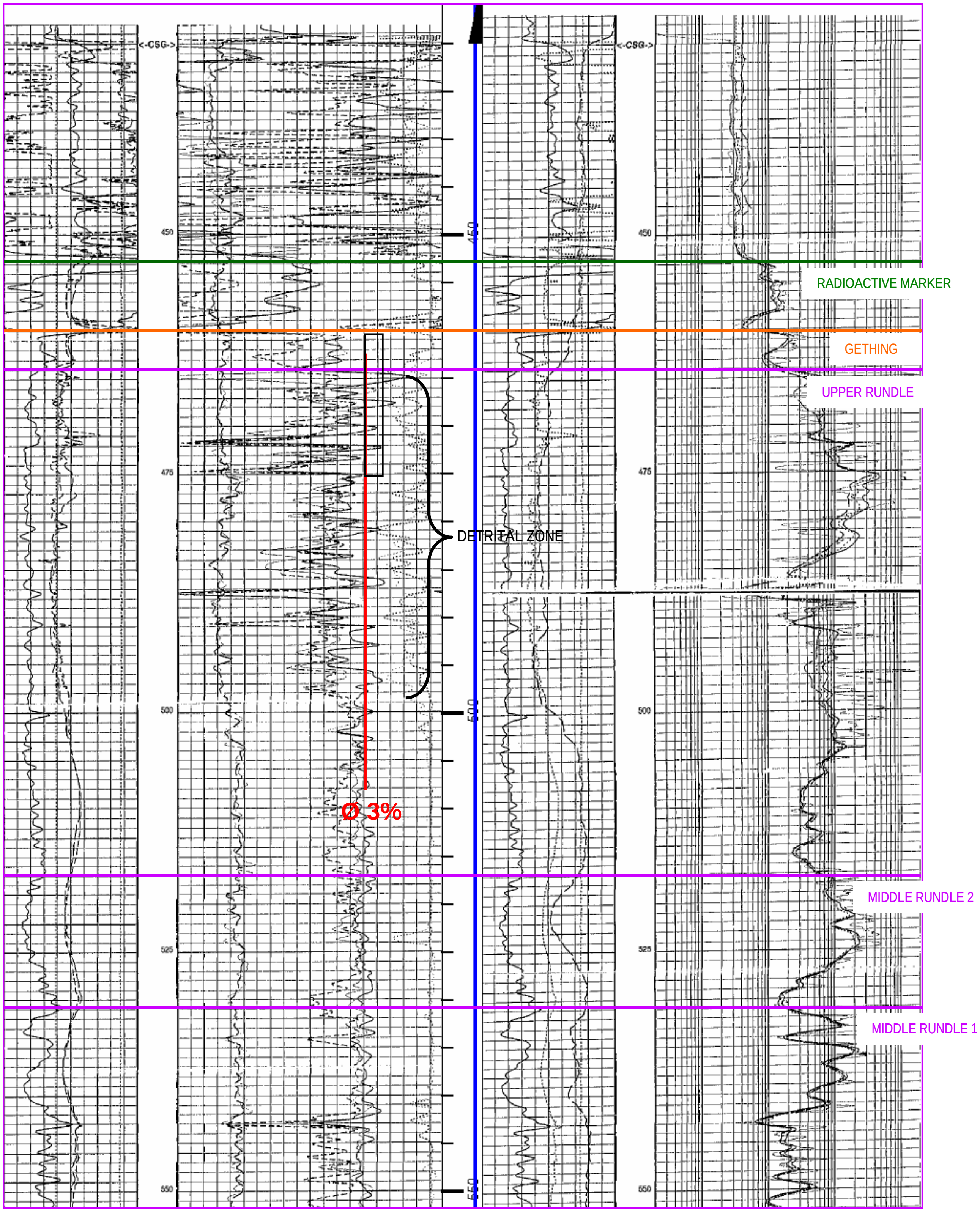


Figure RQ1. Density and induction logs for well d-92-H/94-O-9. Note irregular density, neutron, and caliper curves across the “Detrital” zone from 464 to 500 metres.

- Log control:
  - Full log suite, including carbonate neutron density and PE curves (best)
  - Neutron density logs without PE
  - Sonic log
  - E-logs, gamma-neutron, cased hole logs
  - No logs or gamma only (worst)

Top, base, and net thickness of the dolomitized/enhanced reservoir zone were picked on sample and/or well logs. Reservoir quality codes were assigned as follows:

- E1: excellent reservoir, strong lithology and log support
- E2: excellent reservoir, log evaluation only
- G1: good reservoir, strong lithology and log support
- G2: good reservoir, log evaluation only
- P1: poor reservoir, strong lithology and log support
- P2: poor reservoir, log evaluation only
- CA: enhanced reservoir interval confirmed absent
- ID: insufficient data, cannot confirm presence or absence of reservoir

To provide an estimate of porosity-thickness in support of hydrogeological work and reservoir volumetrics, we assigned excellent reservoir a porosity value of 9%, good reservoir 6%, and poor reservoir 3%. Porosity-thickness values were calculated by assigning a reservoir quality level (E, G, P) to the net reservoir interval in each well, and multiplying by the corresponding porosity value. Thus, for example, a well with 40 net metres of excellent quality reservoir would receive a porosity-thickness value of 40 x 0.09 = 3.6. Reservoir quality codes are posted on each map to give an indication of the reliability of each measurement (thus, an E1 value would receive stronger consideration than an E2 value).

We then produced the following reservoir quality maps:

- Net porous isopach, “detrital zone” enhanced reservoir (Map 12)
- Porosity-thickness, “detrital zone” enhanced reservoir (Map 13)
- Porosity-thickness, lower porosity zone enhanced reservoir (Map 14)
- Porosity-thickness, enhanced reservoir in total Debolt-Rundle interval (Map 15)

These maps provide directional (qualitative to semi-quantitative) measurements of reservoir quality and trends. Note that Maps 13a, 14a, and 15a show the same information, but with HRBPG land blocks outlined.

Maps 12 and 13 show enhanced reservoir development in the “detrital zone” focused along the eastern and southern margins of the basin. The thickest and highest-quality rock is in eastern 94-O-9 and 94-O-16; to the south, the trend of high-quality rock trends slightly southwestward through 94-O-8 and 94-O-1, but well control is not sufficient to define this trend well. Thinner, somewhat lower-grade reservoir is found to the southeast, and patchily distributed along the southern basin margin. Some enhanced reservoir is seen to the west, but there are not enough wells in this area to define trends well.

“Detrital” reservoir quality appears to be developed best in upper Rundle and lower Debolt rocks, particularly near the major north-south Gething valley on the eastern flank of the basin. There is an abundance of relatively clean limestone in these intervals, which appears to be most susceptible to dolomitization and reservoir enhancement.

Enhanced reservoir zones below the unconformity are more patchily distributed around the basin, with most occurrences controlled by only a small number of wells (Map 14). The utility of these zones as water sources/sinks is uncertain because of their poorly-defined volumes, but they may serve as useful secondary zones where there is significant enhanced reservoir in the “detrital zone” (compare Map 13 and Map 15, showing combined porosity-thickness of Mississippian carbonate-enhanced reservoirs).

Mattson Formation

We regarded Mattson sandstones with greater than 6% porosity as having aquifer potential. Thickness of net porous Mattson sandstone is shown on Map 16. Preferential distribution of control wells along the Bovie Fault Zone makes it difficult to accurately depict regional patterns, but westward thickening of the reservoir package is clear. We did not draw a porosity-thickness map for the Mattson, as we felt the scanty well data was not sufficient to add meaningful detail to the net porous sandstone isopach map.

In conclusion, there are enormous reservoir volumes in the Mattson to the west, but not in the immediate vicinity of Horn River Basin gas shale development.

Cretaceous Sandstones

We assigned reservoir potential to Cretaceous sandstones with porosities greater than 3%, based on the importance of coarse-grained Gething sandstones on the eastern flank of the basin. Finer-grained Bluesky and Chinkeh sandstones may not have economic reservoir quality at this level, so porosity-thicknesses in the south and west may be somewhat optimistic.

Map 17 shows porosity-thickness in Cretaceous sandstones (Map17a shows the same information with land blocks overlain). Note that while there are continuous trends attributable to the Gething and Bluesky in the east and south, the porosity-thickness values are generally lower than for the Mississippian carbonates, and more patchily distributed. The patchiness of the reservoir thickness values in the eastern Gething trend may result in part from the difficulty in distinguishing “detrital zone” from Gething intervals.

On the western flank of the basin, Chinkeh porosity-thickness values are also relatively low, except for the high-quality sand body in northern 94-O-15. A more detailed review of wells in this vicinity is recommended to better define Chinkeh reservoir capacity.

Basement Control on Reservoir Fairways

Morrow et al. (2002) and Petrel Robertson Consulting (2005) noted that basin margins and bank edges in northeastern B.C. are preferentially located along deep-seated faults, which may have been active during deposition. Hydrothermal fluids migrated along these same faults, focusing diagnetic processes that enhance reservoir quality, such as solution and dolomitization. Significant faults are coincident in many places with aeromagnetic anomalies interpreted as major basement discontinuities.

Sharp gradients in the total magnetic field may be interpreted as basement domain boundaries, and/or major faults. Map 18 shows the Bovie Fault System lying along steep gradient trends, identified as the boundary between the Liard and Nahanni basement terrances (PRCL, 2005). There does not appear to be any obvious relationship between total magnetic field gradients and the Slave Point margin.

Total magnetic field data can be processed to enhance curvature attributes, which have been shown to assist in detection of more subtle structural features (Roberts, 1998, 2001). Map 19 is a curvature attribute map, with lineaments drawn to emphasize marked curvature boundaries. The Bovie Fault System is obvious on this map as well, but there appears to be no strong relationship between the Slave Point margin and curvature lineament trends. However, a strong trend of north-south lineaments along the western margin of 94-P align strongly with the Gething valley system mapped on the eastern flank of the basin (compare Map 11). Enhanced reservoir quality in the Mississippian also aligns strongly with the trend, and with a more southwesterly trend of lineaments cutting across 94-O-1 (compare Map 12).

Comparing locations of enhanced reservoir quality in the Mississippian below the Detrital Zone (Map 14) with the curvature lineaments of Map 19, we see that a number of these locations lie on or close to interpreted lineaments and sharp gradients – but a more rigorous analysis would be required to determine whether this is a statistically valid relationship.

We speculate from these comparisons that faulting related to basement discontinuities has influenced Mississippian reservoir quality, by governing access to fluids responsible for solution and dolomitization. Additional work should be done to test this idea at a more local scale.

INTEGRATION OF STRATIGRAPHIC MAPPING AND HYDROGEOLOGIC CHARACTERIZATION

Canadian Discovery Ltd.'s study "Hydrogeologic Characterization of Horn River Basin Aquifers" is included with this report as Appendix V. Integration of this work with our geological report provides some additional insights into HRB aquifers, and their capacity to serve as water sources and sinks for completion operations. Our review focuses on their analysis of the Debolt-Rundle carbonate platform, as Mattson and Cretaceous sandstone data are not sufficient to support regional analysis.

Several components of Canadian Discovery's work stand alone, and are not discussed further here. These include:

- Pressure-Elevation graphing
- Hydraulic head mapping
- Pressure over Depth (P/D) mapping
- Available head mapping
- Formation water chemistry mapping
- H_2S chemistry mapping

Resource Volume Mapping

Canadian Discovery (CDL) has created contour maps of total water volume in the Mississippian carbonate platform, per section (square mile), assuming an average 2% porosity through the non-enhanced portion of the platform, and 3% (Encl. 15), 6% (Encl. 16), or 9% (Encl. 17) average porosity through the reservoir interval demonstrating enhanced porosity (Map 12 of this report). CDL concluded that approximately 80 x $10^9 m^3$ water is contained in non-enhanced Debolt-Rundle reservoirs, while the enhanced reservoir section contains 5 x $10^9 m^3$, 10 x $10^9 m^3$, or 15 x $10^9 m^3$, assuming average enhanced reservoir porosities of 3%, 6%, and 9%, respectively.

PRCL feels that the water volumes contained in the enhanced reservoir intervals are of much greater interest than those contained in the 2% country rock. The "enhanced" waters have access to high-permeability reservoir conduits, and will thus be most readily moved during production / injection operations. We suggest that it would be worthwhile to map enhanced reservoir volumes only, and to do so based upon the interpretive porosity-thickness map of the entire enhanced reservoir interval (Map 15 of this report) – as opposed to computer contouring values calculated at each wellbore.

Regardless of methodology, water volumes contained in Debolt-Rundle enhanced reservoirs are immense, and are concentrated along the eastern and southern flanks of the Horn River Basin, where enhanced reservoirs are best developed.

Permeability Analysis

Canadian Discovery considered core, DST, and HRBPG well-test data in trying to characterize permeabilities in the Debolt-Rundle section.

Core has been recovered primarily from regional (non-enhanced) reservoir intervals in the Debolt-Rundle, because:

- Such intervals are volumetrically dominant,
- Enhanced reservoir intervals are difficult to target for coring prior to log evaluation of the wellbore, and
- Core recoveries from enhanced reservoir intervals are generally poor.

CDL's Fig. 5, a porosity-permeability crossplot based on core analysis data, thus demonstrates generally poor reservoir quality in regional strata, but reveals little about the enhanced reservoir section. Their Encl. 20 shows no core analysis values from wells with substantial enhanced reservoir sections.

DST analyses are better indicators of enhanced reservoir permeabilities, as some DST's have been run as post-drilling staddle tests, preferentially over enhanced reservoir intervals picked on logs. CDL Encl. 20 shows good examples of enhanced reservoir permeability at b-6-G/94-O-7 and d-73-H/94-P-4. DST values less than 10 mD are generally from tests across marginally enhanced to regional (unenhanced) Debolt-Rundle sections.

Analyses of pumping and injection tests exhibit the highest permeability values, ranging up to 39,800 mD (CDL Encl. 20). As noted by Canadian Discovery, these tests have the widest radius of investigation, and hence are most likely to encounter fractures that might enhance permeability measurements. However, more critically, the well tests analyzed for this study have been run across substantial intervals of enhanced reservoir quality, evident on logs and in cuttings (Table 1).

Table 1. Comparison of reservoir permeability measured from well test analysis, versus porosity-thickness of Debolt-Rundle enhanced reservoir section.

Well	Test Analysis Permeability (mD)	Porosity-Thickness (Φ-m)
d-A94-A/94-O-8	0.1	0.67
d-90-G/94-O-8	10000, 36000	1.32
b-16-I/94-O-8	39,800	0.9
c-67-K/94-O-8	1,400	1.14
a-77-K/94-O-8	1,400	1.47
a-2-J/94-O-9	1,100	1.33
d-61-A/94-O-15	Tight (not analyzed)	0.02
c-C68-B/94-O-15	11,900	0.15

The first six wells in Table 1 lie in the fairway of high reservoir quality along the eastern flank of the HRB, and all exhibit relatively high porosity-thickness values. High test analysis permeabilities were calculated, except in d-A94-A/94-O-8. Looking more closely at this well, which lies on the margin of the high-quality fairway, we see the porosity-thickness data are suspect. Clow's sample cuttings log (Appendix 3) shows low-quality limestones, but the wellsite sample log shows more dolomite. On the basis of the wellsite log, an optimistic reservoir quality was interpreted. However, the poor test results indicate that the Clow interpretation of poor reservoir quality is more likely correct.

On the western side of the basin, the two wells in 94-O-15 produced very different flow test results. Both tested a thin porous streak in the middle Rundle. At c-C68-B, cuttings sampled a thin, high-quality reservoir section, whereas at d-61-A, high-quality rock was not evident in cuttings, and the porosity log expression of the interval was less pronounced. It appears that this test has sampled high-permeability reservoir and/or fractures, but reservoir volume may be relatively small.

We conclude that there is a reasonably good relationship between mapped porosity-thickness values and permeabilities measured by DST and well test analysis. Although local variations will occur, we expect most wells drilled in the Debolt-Rundle high porosity-thickness fairways on the eastern and southern wells of the basin will exhibit good permeabilities.

Well Deliverability

CDL modeled three cases for water well deliverabilities over time:

- A high-deliverability case, using a 50-metre thick dolomitized/enhanced reservoir section with porosity of 18%, and a large (10x5 km) reservoir area

- A low-deliverability case, based on three reservoir zones up to 20 metres thick, with permeabilities of 10 mD or less
- A "channel" reservoir case, with reservoir parameters like the high-deliverability case, but with a reservoir area of only 10x1 km.

Given the continuity of porosity-thickness trends mapped on the eastern flank of the basin, we feel it is reasonable to expect the performance modeled by the high-deliverability case for many wells drilled in this area. Smaller reservoir volumes, such as those associated with isolated enhanced reservoir sections in the middle of the carbonate platform, would likely yield lesser water volumes, as for the channel reservoir case. We believe it is unlikely that operators would choose to try to produce water from carbonates sections with the low-deliverability parameters, as they would be highly unlikely to produce the required volumes and rates.

Well Injection

CDL modelled injectivity assuming an enhanced reservoir volume of 50 metres thick by 10 km long by 5 km wide – the same volume as the high-deliverability production case above. PRCL believes that such a model is reasonable, given the continuity of enhanced reservoir mapped along the eastern flank of the basin.

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APPENDIX I

Databases

(on enclosed CD)

APPENDIX II

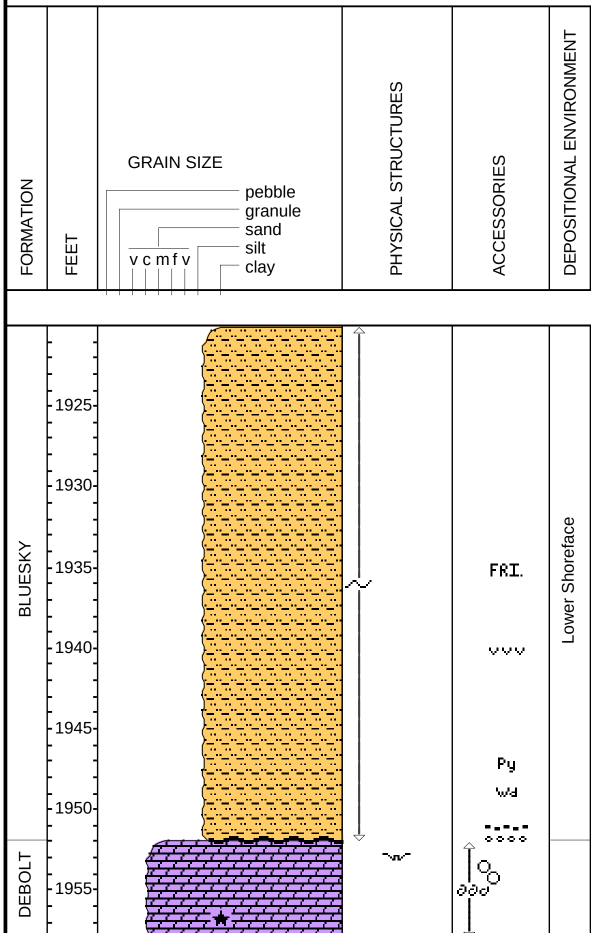
Applecore™ Graphic Core Logs

BIVOUAC CRETACEOUS
APPLECORES

Mobil Sahtaneh
C-70-I 94-I-12

Date Logged: March 16, 1999
Logged by: PETREL ROBERTSON CONSULTING LTD.
Remarks: Core #1: 1920 - 1958 (Rec. 38 feet)

3.5" core, unslabbed, dirty



REMARKS

Medium to dark grey, massive argill. siltstone

Burrowed aspect, but features difficult to see on unslabbed surfaces

Lower 8-10 feet features coal fragments, pyrite masses (some replacing burrow traces)

Scoured base, with green waxy mineralization and a few chert granules

Dolomitic skeletal grainstone and wackestone
Fractured, possibly karsted
Calcite crystals and pyrobitumen line fractures

Westar Conoco Elleh

C-40-K 94-I-12

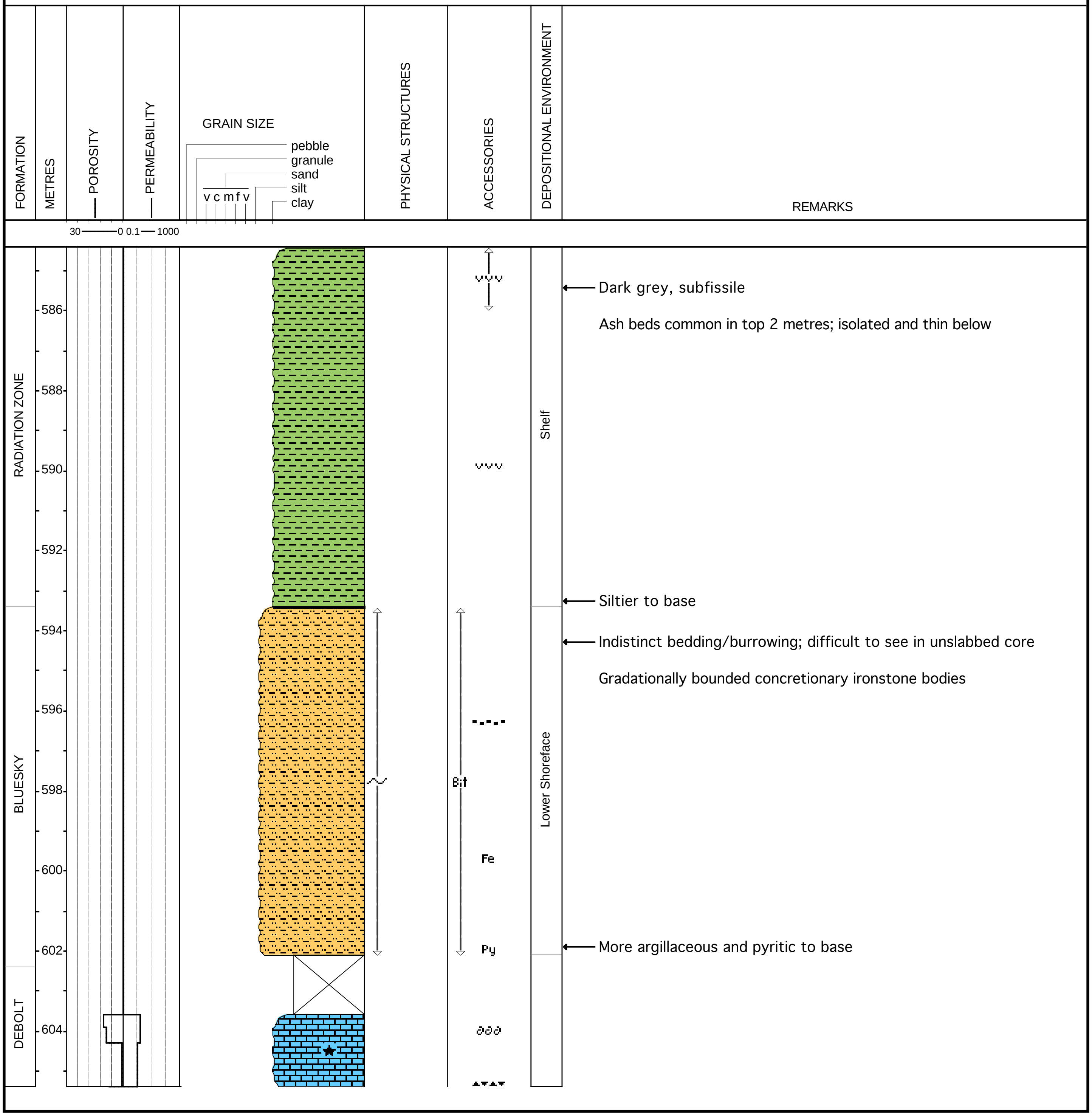
Date Logged: March 16, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 584.4 - 602.6 (Rec. 17.4 m)

Core #2: 603.6 - 610.8 (Rec. 7.0 m)

3.5" core; Core 1 unslabbed, Core 2 slabbed



Mobil Sahtaneh

B-26-B 94-I-13

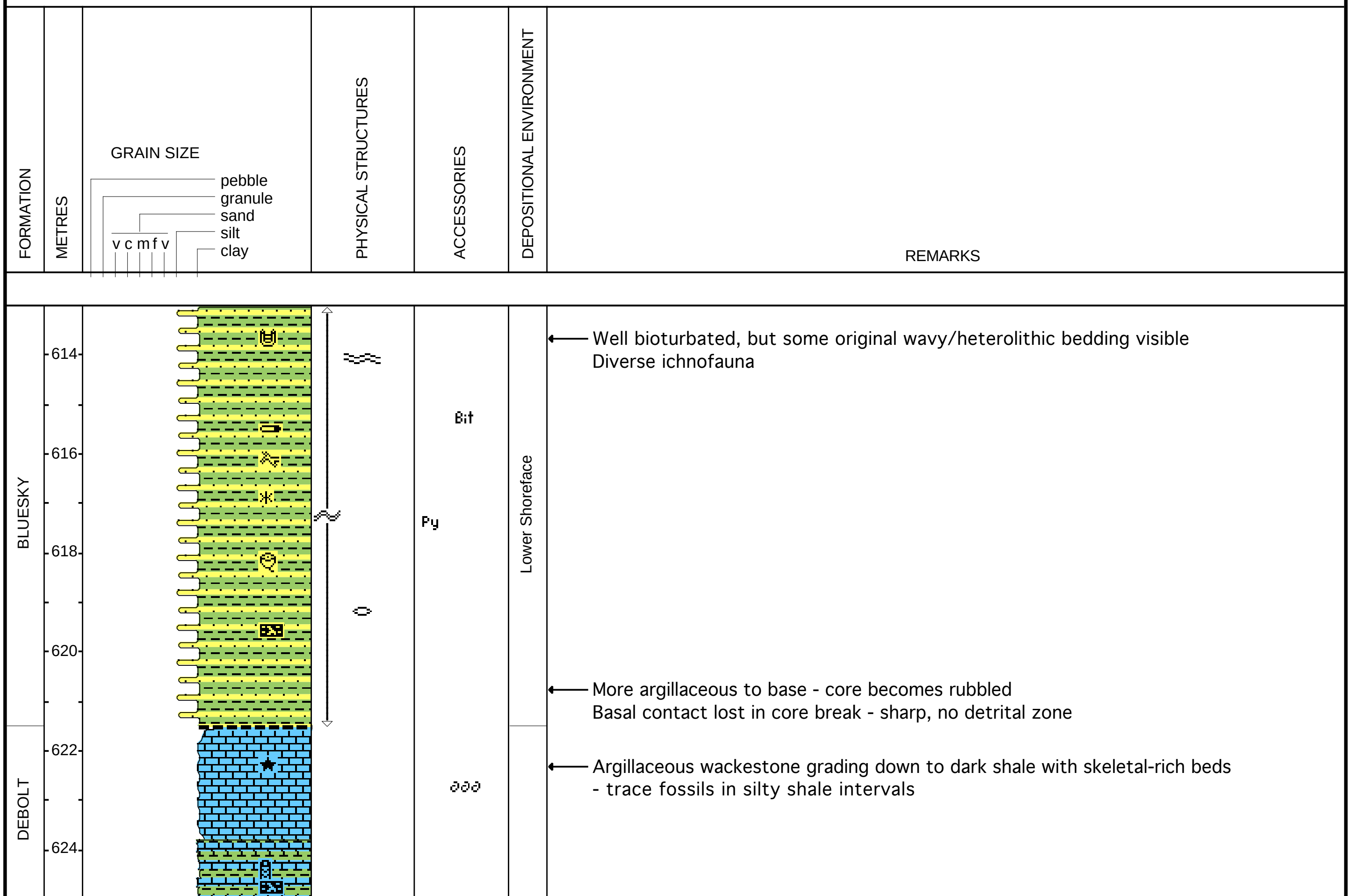
Date Logged: March 16, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 613 - 621.5 (Rec. 8.5 m)

Core #2: 621.5 - 628.25 (Rec. 6.75 m)

2.5" core, slabbed



Mobil Sahtaneh

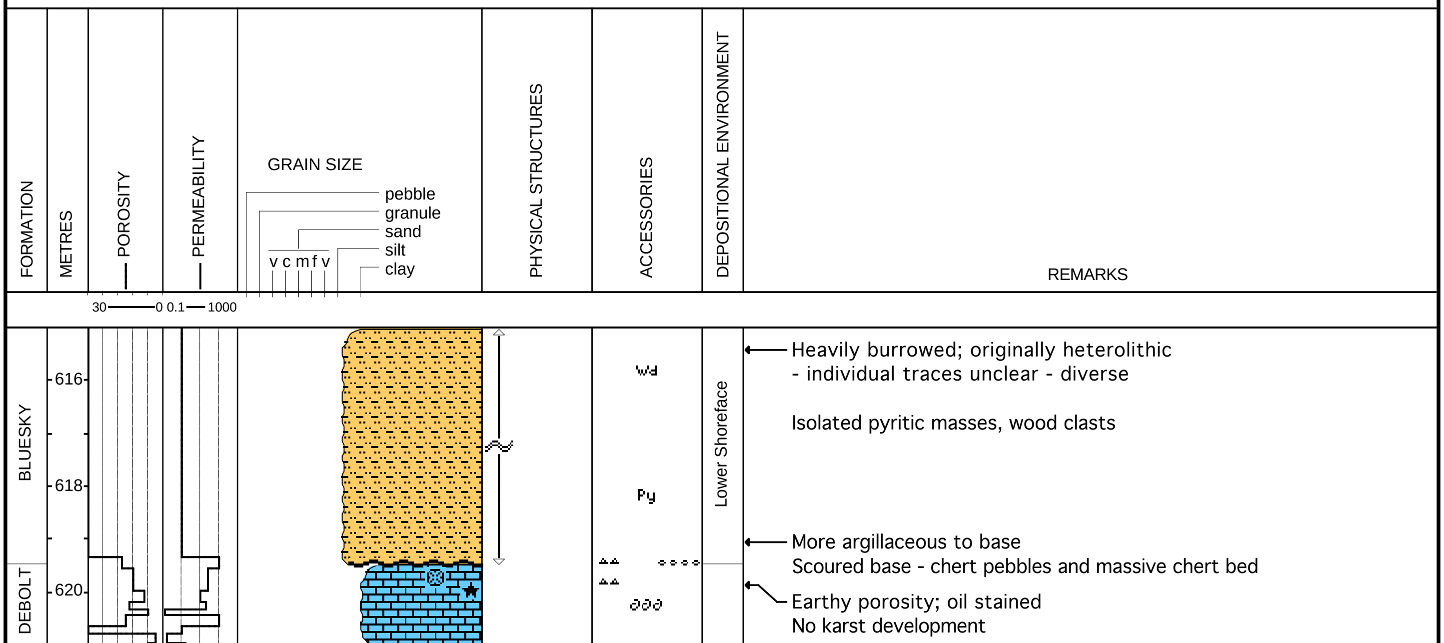
A-8-B 94-I-13

Date Logged: March 16, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 615 - 629 (Rec. 13.75 m)

4" core, slabbed



Cdn Res Quintana Pac Kotcho

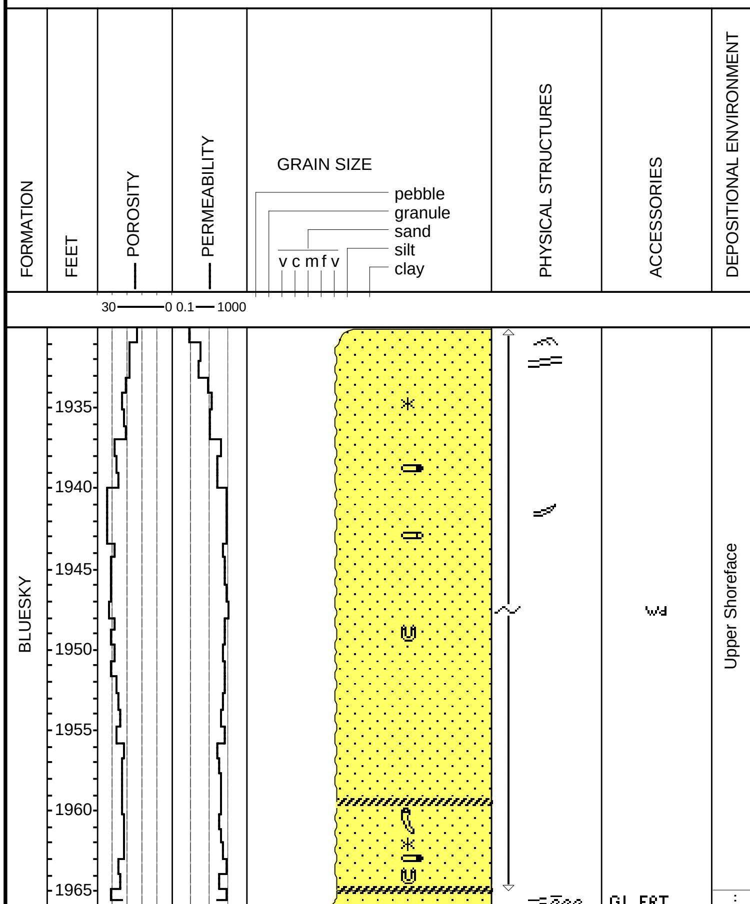
B-68-H 94-I-14

Date Logged: March 17, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1930 - 1966 (Rec. 36')

3.5" core, unslabbed, clean



REMARKS

Well sorted, tripolitic chert
Bioturbation moderate but pervasive
- highlighted by burrow linings; little lithic contrast otherwise

Minor oil staining to base

More diverse and abundant bioturbation

Transgressive
Laminated, carbonaceous partings - bundle beds?
Minor soft-sediment deformation

Mobil Sierra

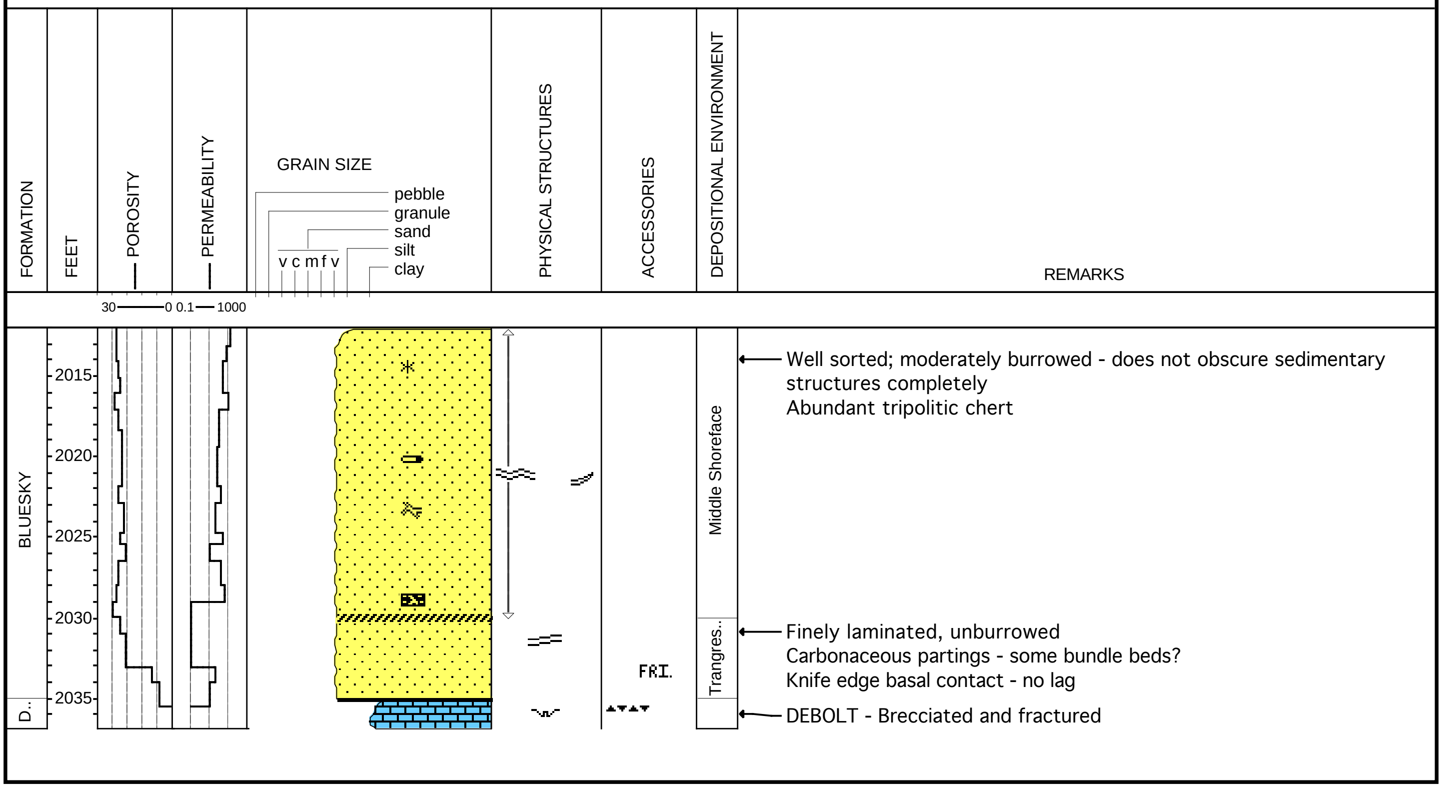
D-92-D 94-I-14

Date Logged: March 16, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 2012 - 2037 (Rec. 25')

3.5" core, unslabbed



Shell Kotcho

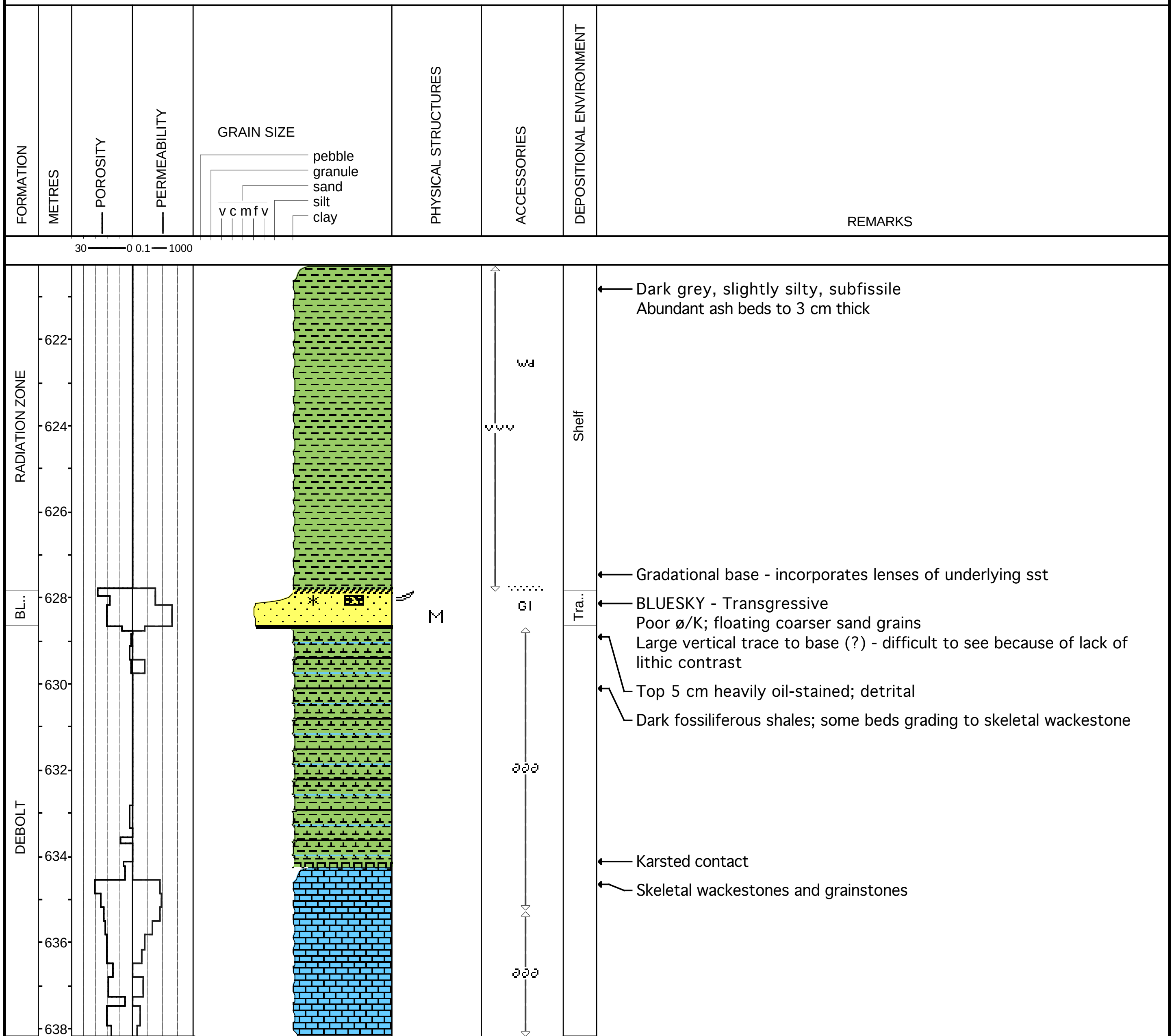
B-A15-K / 94-P-3

Date Logged: March 17, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 620.25 - 638.4 (Rec. 17.95 m)

4" core, slabbed



Elf Cli

D-33-L / 94-P-11

Date Logged: March 17, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

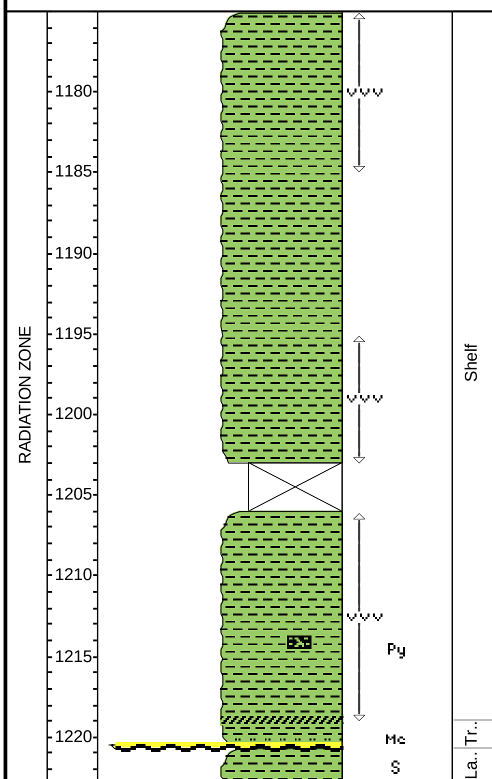
Remarks: Core #1: 1175 - 1203 (Rec. 28')

Core #2: 1203 - 1206 (No rec.)

Core #3: 1206 - 1223 (Rec. 17')

4" core, unslabbed, clean

FORMATION	FEET	GRAIN SIZE (pebble, granule, sand: v c m f v, silt, clay)	ACCESSORIES	DEPOSITIONAL ENVIRONMENT	REMARKS



Dark grey, slightly silty
Abundant ash beds

Volcanic (tuffaceous) sandstone beds 1187 - 1192
- 3 beds > 20 cm thick

Fewer ash beds, more fissile, less silt

Mineralized Chondrites traces

Transgressive - Siltier, with micaceous surfaces

Large rounded chert pebbles in green mudstone; rubbly recovery

BLUESKY - Marginal marine/bay
Black, carbonaceous (?); different character than upper shales

Ammin Ootla

C-85-J / 94-P-12

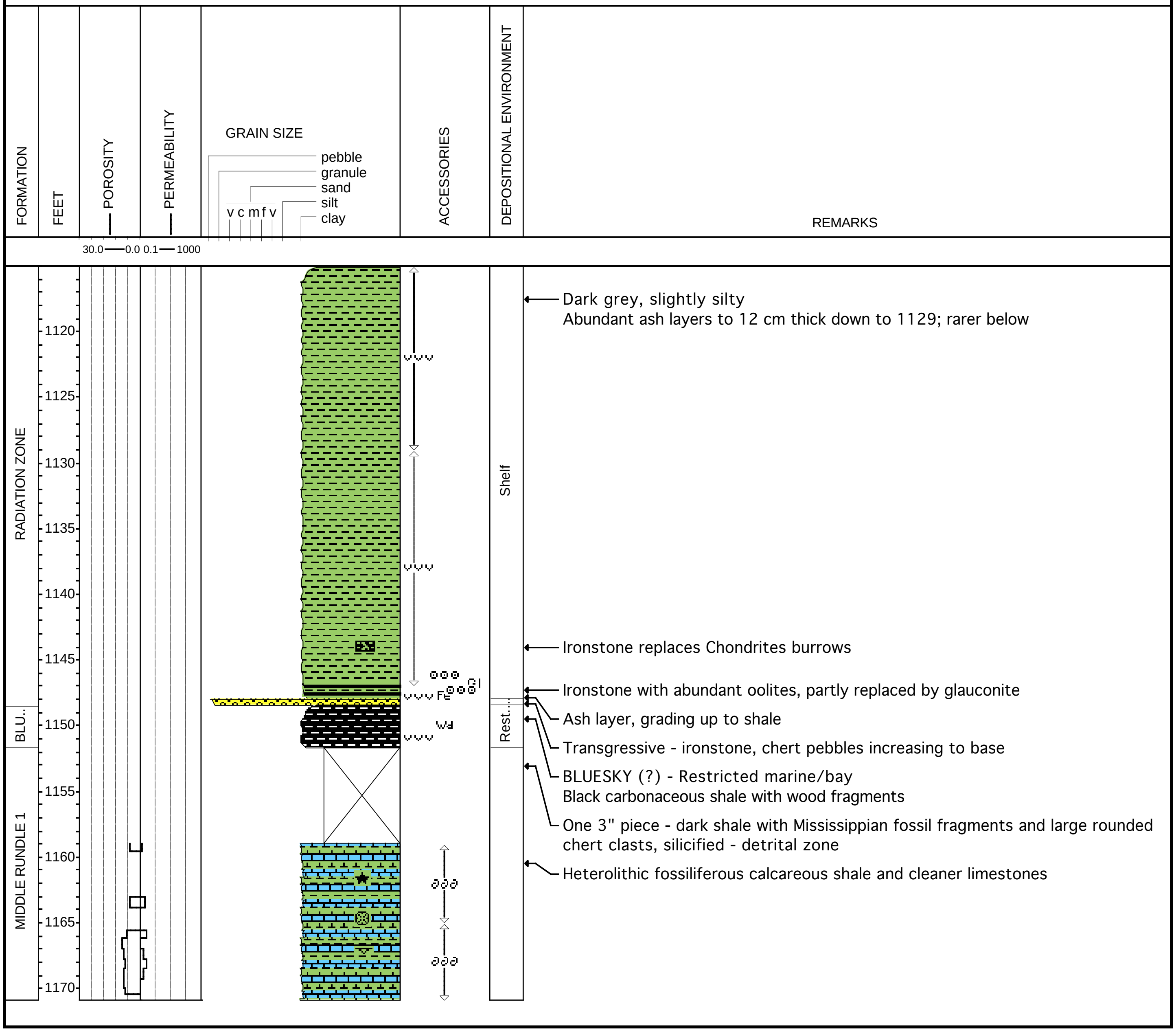
Date Logged: March 17, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1115 - 1158 (Rec. 38')

Core #2: 1159 - 1173 (Rec. 12')

3.5" core, slabbed



Amerada Hyperion

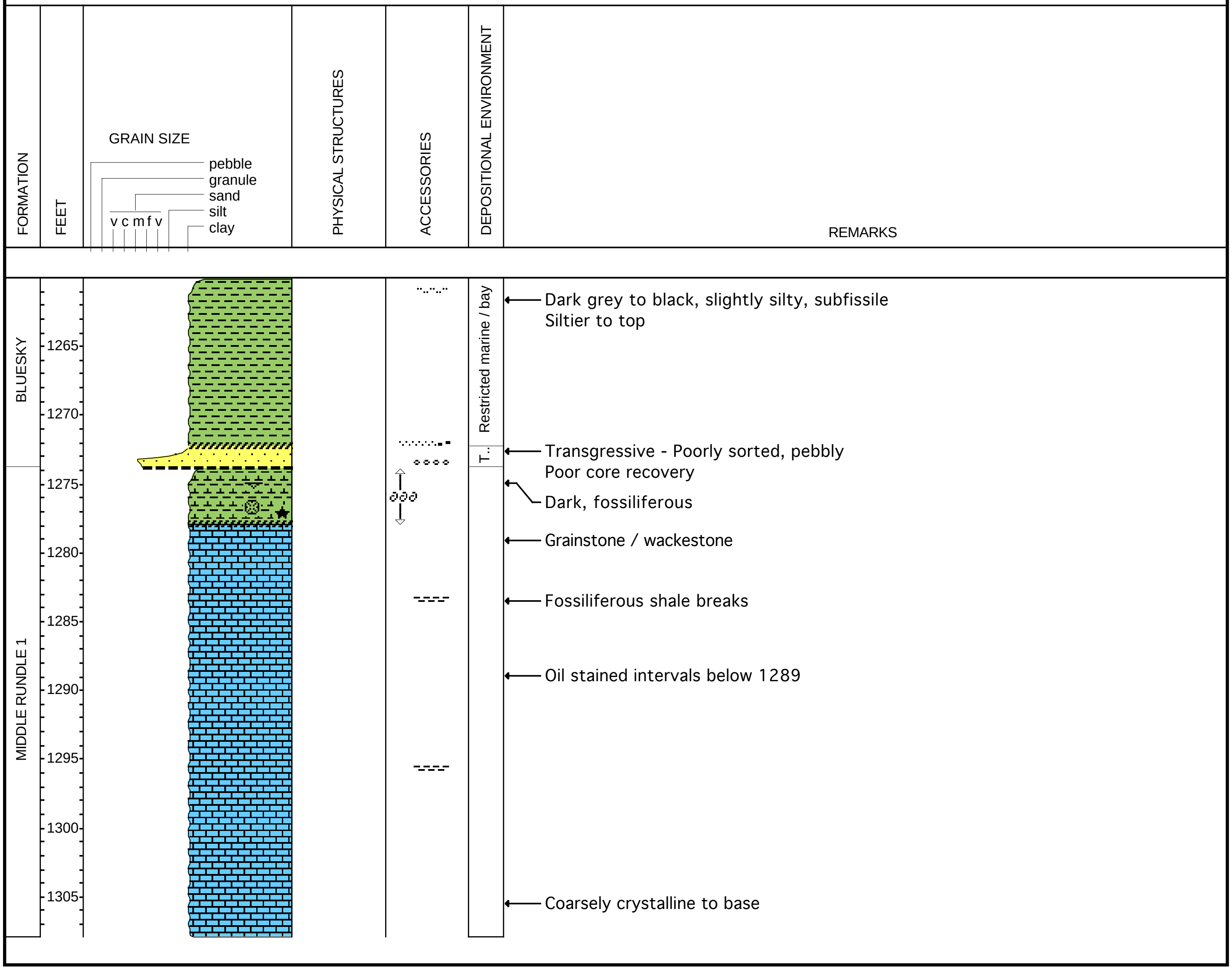
B-29-J 94-P-12

Date Logged: March 17, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1260 - 1318 (Rec. 48')

2.5" core, unslabbed, somewhat dirty



Mobil North Petitot

D-33-E / 94-P-13

Date Logged: March 17, 1999

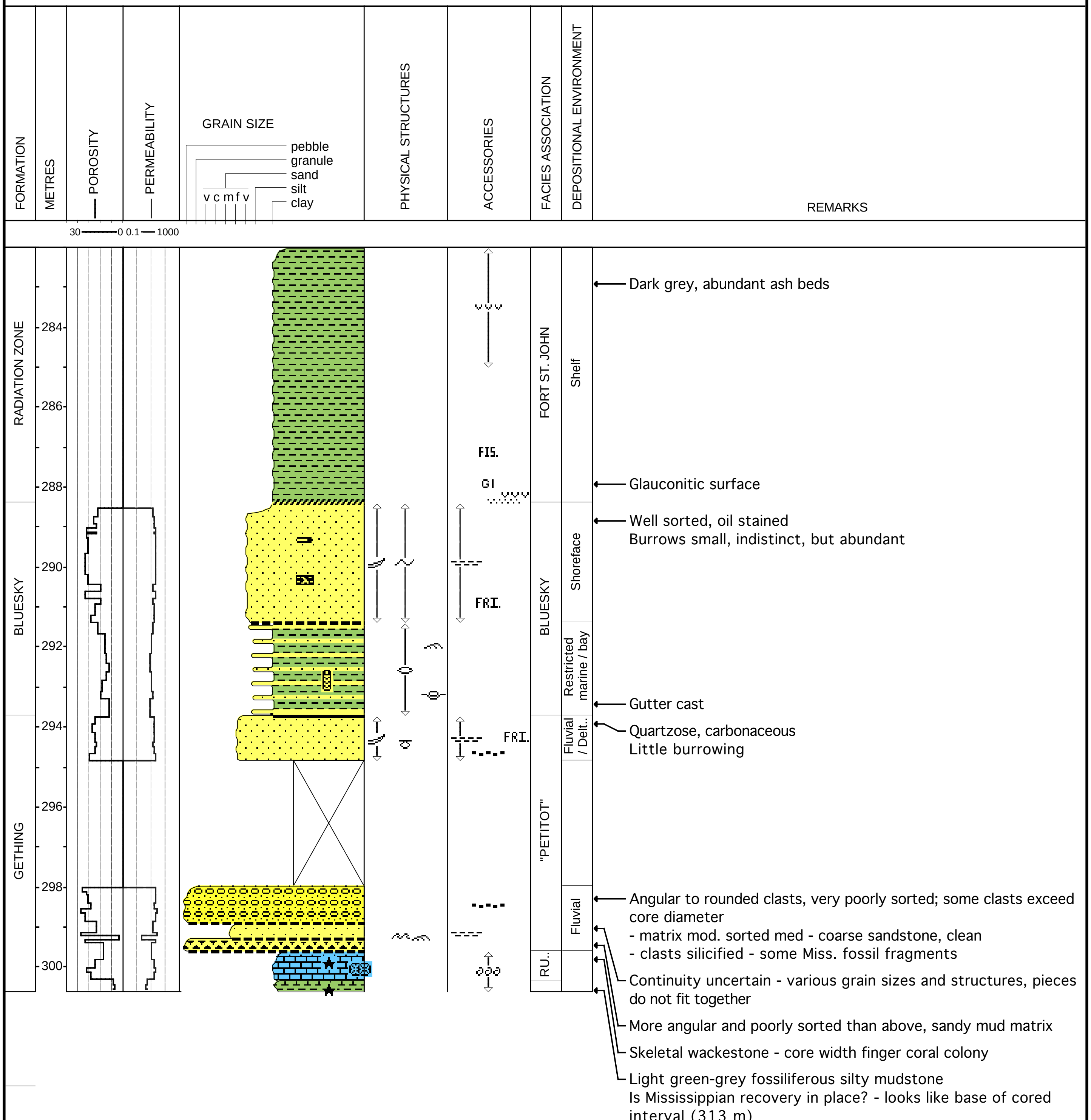
Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 282 - 298 (Rec. 12.85 m)

Core #2: 298 - 316 (Rec. 2.9 m)

- Recovery interval Core #2 questionable

3.5" core, slabbed

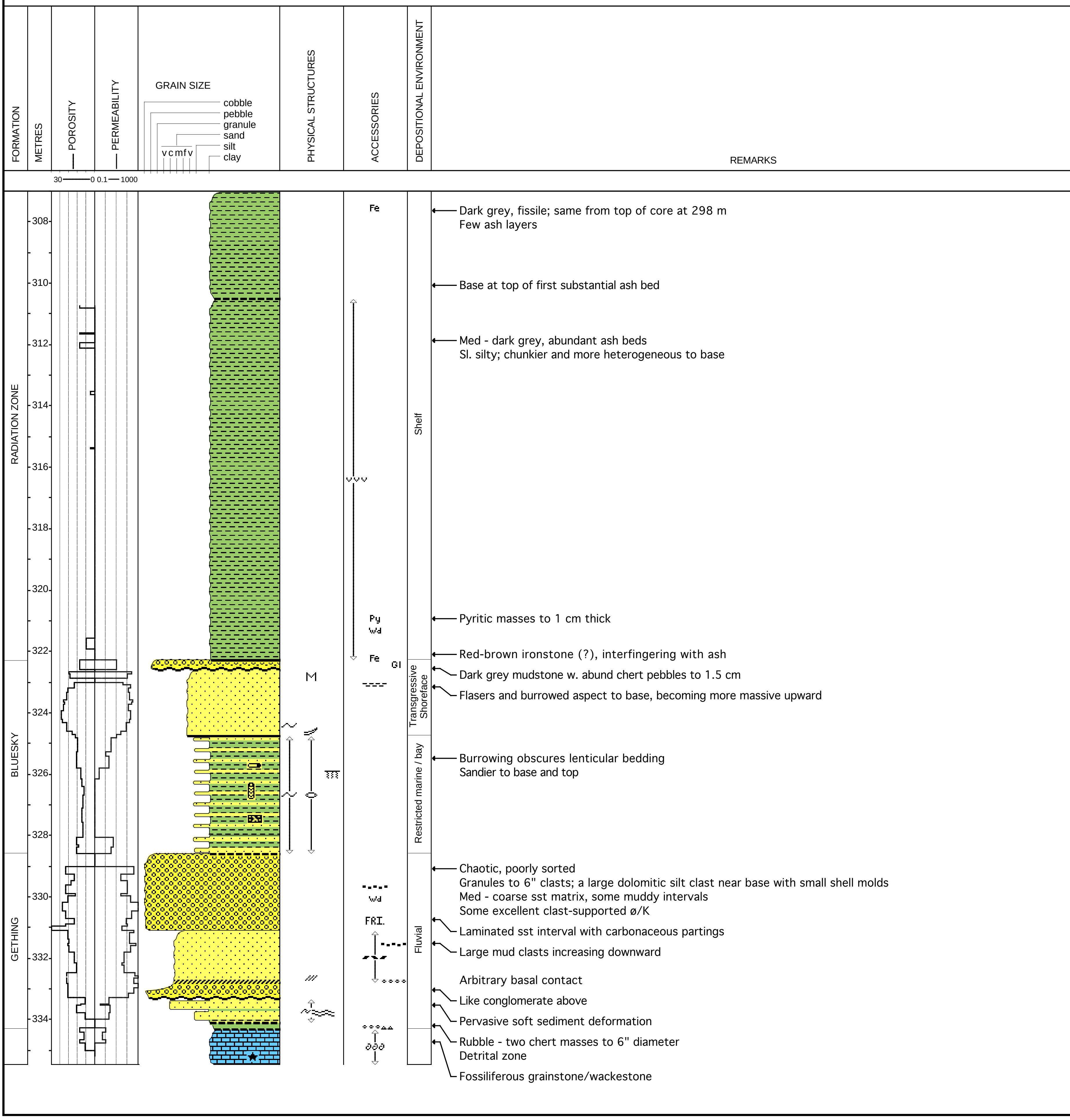


Mobil North Petitot

D-33-F 94-P-13

Date Logged: March 17, 1999
Logged by: PETREL ROBERTSON CONSULTING LTD.
Remarks: Core #1: 298 - 313 (Rec. 14.8 m)
Core #2: 313.5 - 329 (Rec. 15.1 m)
Core #3: 329 - 343 (Rec. 6.2 m)
- Recovery interval of Core #3 questionable

3.5" core, slabbed



UCEL Hossitl

D-100-J 94-P-14

Date Logged: March 18, 1999

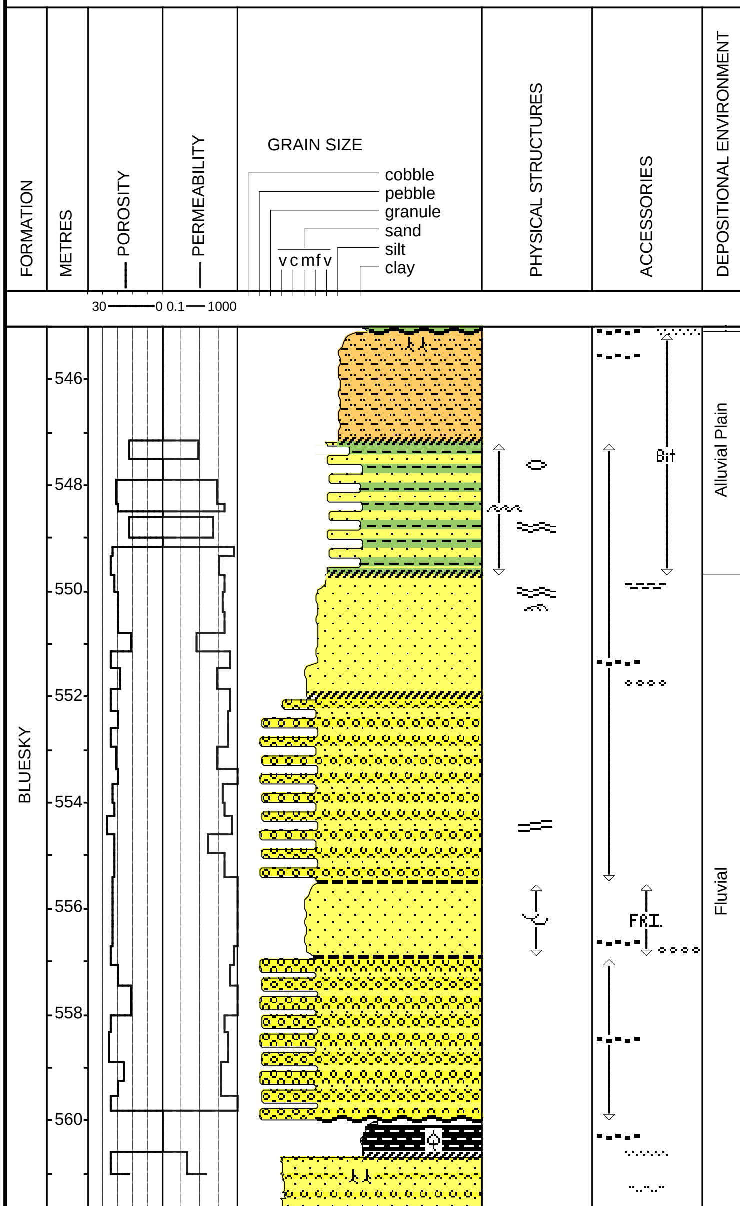
Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 545 - 549 (Rec. 4.0 m)

Core #2: 549 - 558 (Rec. 9.0 m)

Core #3: 558 - 561.75 (Rec. 3.75 m)

3" core, unslabbed, clean



REMARKS

BLUESKY - Transgressive
Scoured base with 1 -2 cm relief; lithified clasts of underlying unit

Well consolidated - long core pieces
More argillaceous to base

Wavy/lenticular bedding overprinted by soft-sediment deformation
Core analysis samples in sandy beds overstate reservoir quality of interval

Poorly sorted, more pebbly to base
Abundant coal clasts, as large as core diameter

Interbedded sst and conglomerate, v. poorly sorted
Conglomerates matrix and clast-supported; pebbles subang. to rounded, chaotic orientations, chert and dolomite
Fine sandstone interbeds, rippled to heterolithic

Relatively homogeneous and well-bedded; bedding highlighted by carb. partings
Pebbles and coaly clasts in basal 30 cm

Like conglomerate above, but less fine-grained sand
Pebbles up to 6 cm

One mineralized fracture/fault plane
Heterolithic to base

Med-coarse pebbly sandstone to conglomerate, interbedded with silty rooted intervals

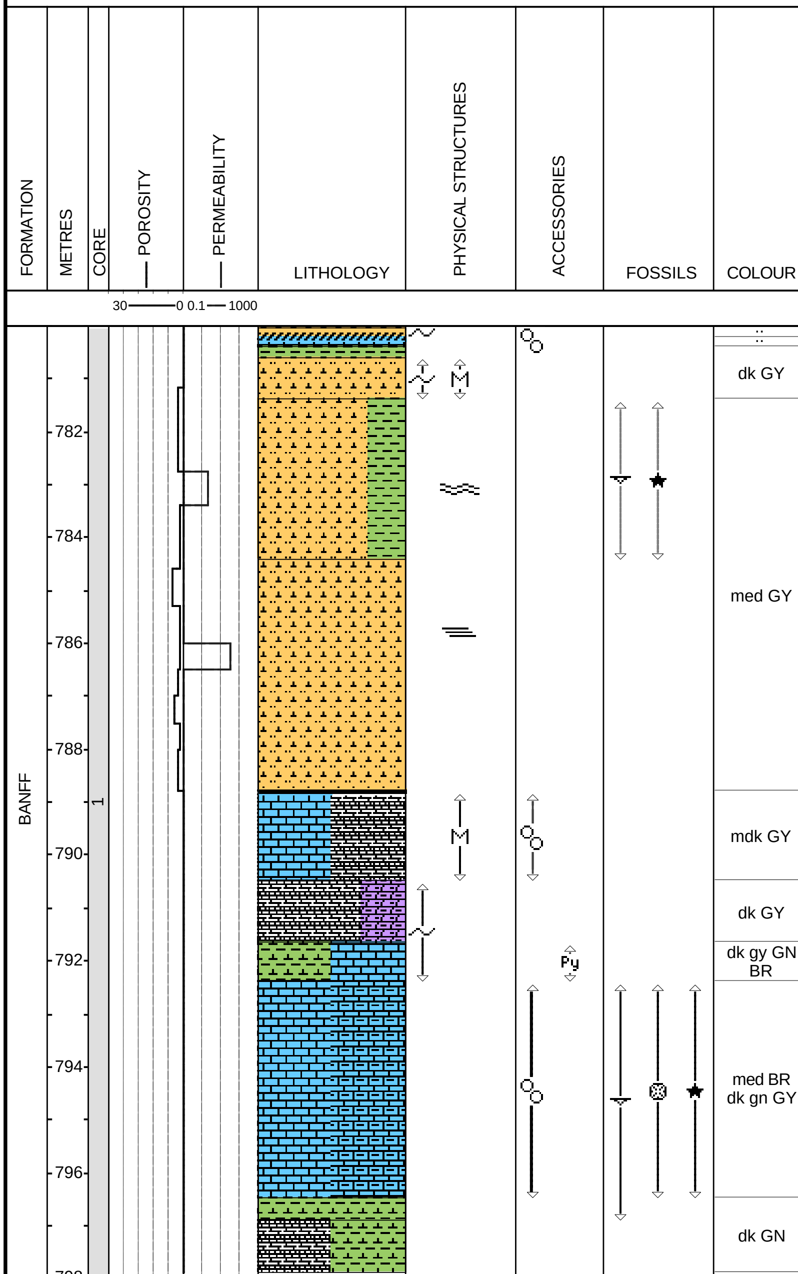
BIVOUAC MISSISSIPPIAN
APPLECORES

PCI East Kotcho

C-077-G 094-I-14

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.



REMARKS

- LIMESTONE: Argillaceous, nodular, silty.
- MUDSTONE: Calcareous, dark grey, blocky.
- SILTSTONE: Calcareous, well sorted mostly planar bedded; thin to medium bedded; upper 3.0 metres less well-bedded, with partings and interbeds of greenish calcareous MUDSTONE which carry rare crinoid and brachiopod detritus.
- LIMESTONE: Slightly argillaceous dark grey mudstone, possible silty; rare bits wackestone.
- MUDSTONE: Argillaceous, dark grey, dolomitic.
- INTERBEDDED (50:50) SHALE, slightly calcareous, laminated; and LIMESTONE, mudstone.
- Nodular, argillaceous LIMESTONE: Nodules to irregular bands of LIMESTONE, mudstone to (rare) wackestone in matrix of calcareous SHALE; 10% - 15% coarse skeletal debris.
- SHALE: Calcareous, dark green, laminated, fissile; well preserved brachiopods including spiriferids.
- Interbedded nodular lime MUDSTONE, as above, and SHALE, as above, approximately 50:50.

Texaco Kotcho

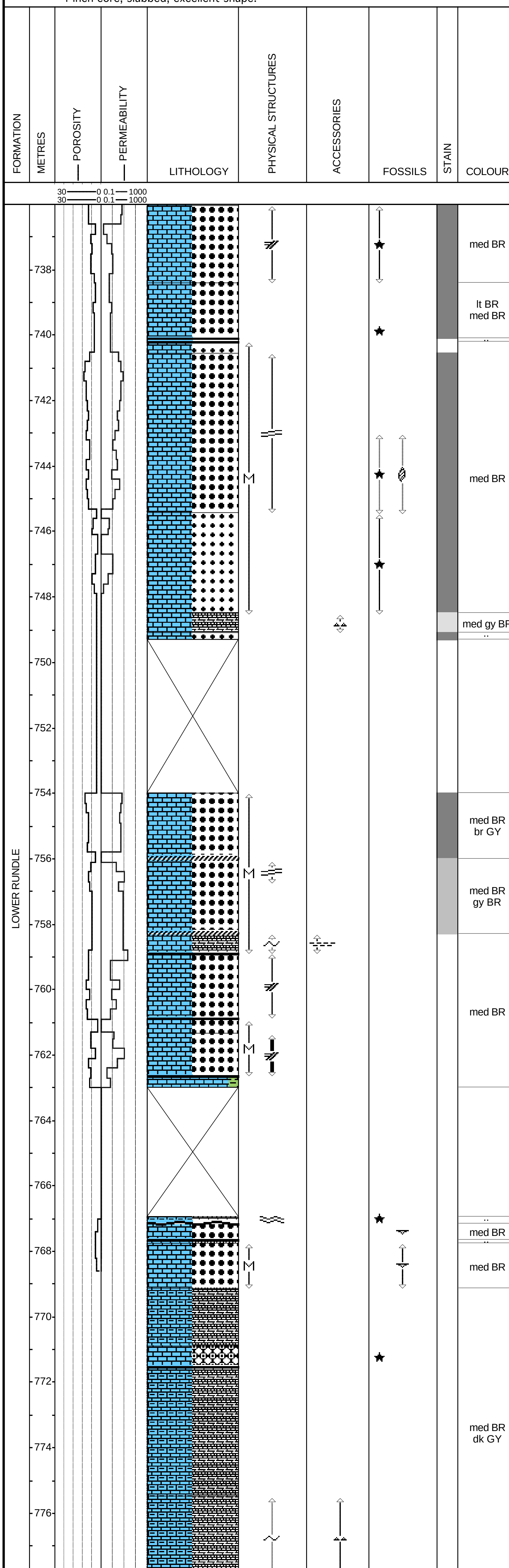
D-093-C 094-P-03

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 736.00-754.00m; Cut: 18.00m; Rec'd: 13.35m
Core #2: 754.00-767.00m; Cut: 13.00m; Rec'd: 9.00m
Core #3: 767.00-778.00m; Cut: 11.00m; Rec'd: 11.00m

4 inch core; slabbed; excellent shape.



REMARKS

- Medium brown, well bedded, interbedded fine- and coarse-grained crinoidal packstone; fair to very good sorting; oil-stained (relict oil saturations in finer grained beds). Basal contact at 2cm, black calcareous SHALE.
- More massive bedded calcsiltites to very fine packstone; at base 20cm very coarse-grained, poorly-sorted crinoidal packstone.
- Mudstone/wackestone sandwiched between two beds of SHALE, black, non-calcareous.
- Wackestone/packstone, poorly sorted, tight. Thin to medium bedded.
- Thin to medium bedded; interbedded coarse- to very coarse-grained skeletal packstone; oil-stained.
- LIMESTONE: Faintly thin to medium bedded, very fine to fine packstone, calsiltite; very well sorted.
- Medium brown massive to faintly bedded; poor to fairly sorted wackestone/packstone, coarsening and cleaning upward, oil stained.
- Brown grey, mudstone; thin to medium bedded; small, elongate white CHERT nodules.
- As in interval 745.45 - 748.50m. Tight.
- Medium brown, coarse- to very coarse-grained crinoidal packstone/grainstone? fair to very good sorting. No bedding.
- Medium brown, thin to medium bedded, well sorted calcsiltites and very fine-grained packstone; no coarse debris; few argillaceous laminae. Oil stained in part.
- Medium brown, thin to medium bedded; interbedded fine- to very coarse-grained, skeletal packstone/grainstone, planar cross-bedded (15 - 20 deg.).
- Fine-grained, very well sorted packstone.
- Interbedded LIMESTONES, as in above 2 units; approximately 50% cross-bedded.
- Coarse-grained packstone/grainstone, well sorted with three sharply bounded black shale beds.
- Poorly sorted, medium brown, fine- to vary coarse-grained crinoidal packstone.
- Same as 767.15 - 767.65m.
- Interbedded medium brown mudstone and strongly argillaceous MUDSTONE to calcareous SHALE; latter finely laminated, interbeds of LIMESTONE, coarse- to very coarse-grained, poorly sorted mudstone/wackestone.
- Single bed coarse grained well sorted crinoidal packstone/grainstone.
- Little skeletal debris or interbeds of wackestone/packstone; large, ovate CHERT nodules, dark grey in basal metre.

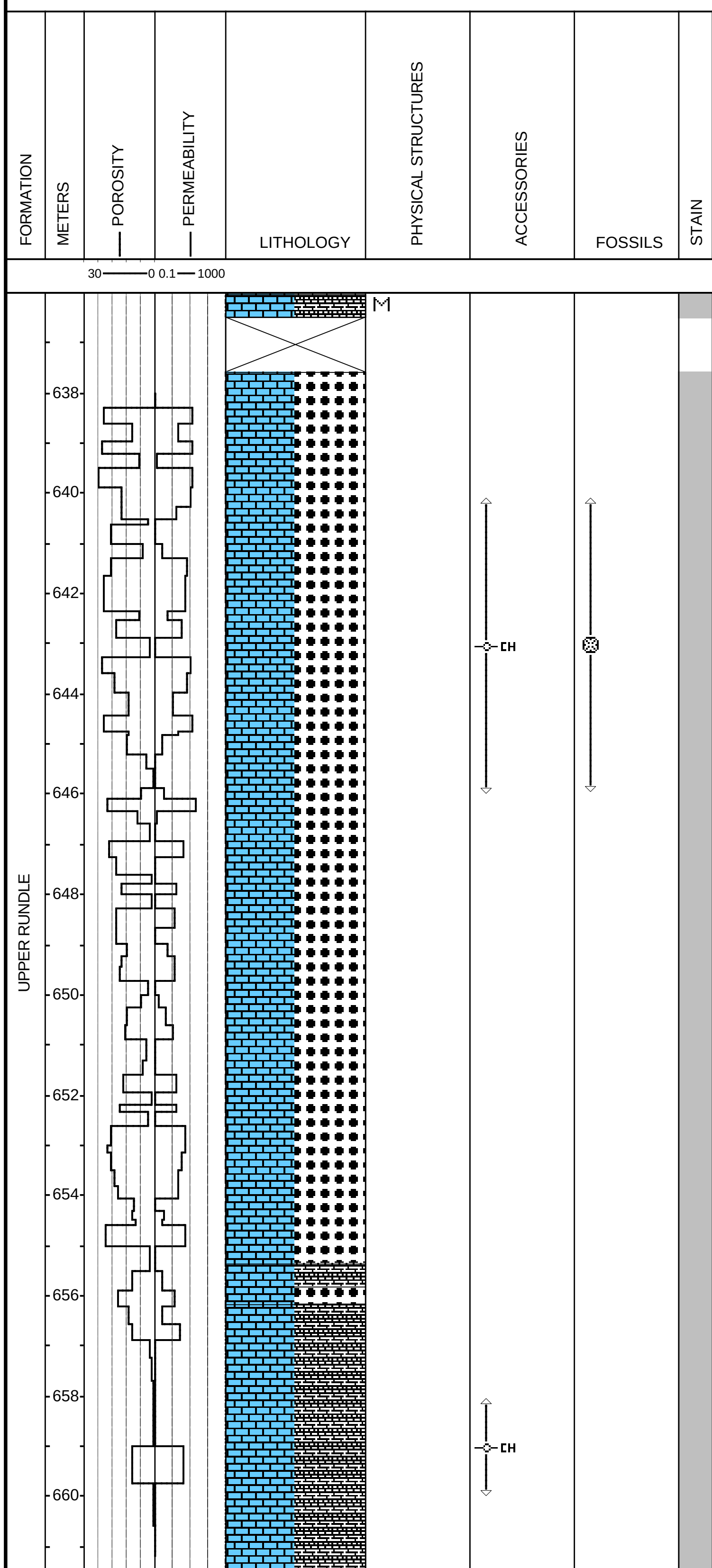
Shell Kotcho
A-76-K 94-P-03

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1 636.00-637.60 m Cut: 1.60 m Rec'd: 0.5 m? 1box
Core #2 637.60-656.20 m Cut: 18.60 m Rec'd: 18.60 m 14 boxes
Core #3 656.20-661.70 m Cut: 5.50 m Rec'd: 5.50 m 4 boxes

4-inch core; slabbed; poor-excellent shape.



REMARKS

LIMESTONE: light brown; ?mudstone; oil-stained. Rubble.

Light brown, very well sorted, homogeneous, very fine- to fine- grained packstone, porosity intergranular, chalky; no signs of bleeding or bioturbation; rare horn corals, occasional irregular layers of grey chert. Grades to lime mudstone at base.

LIMESTONE: as above, but finer, calsiltite to mudstone, aphanitic, odd grey CHERT layer; oil stained.

Texex et al Tsea

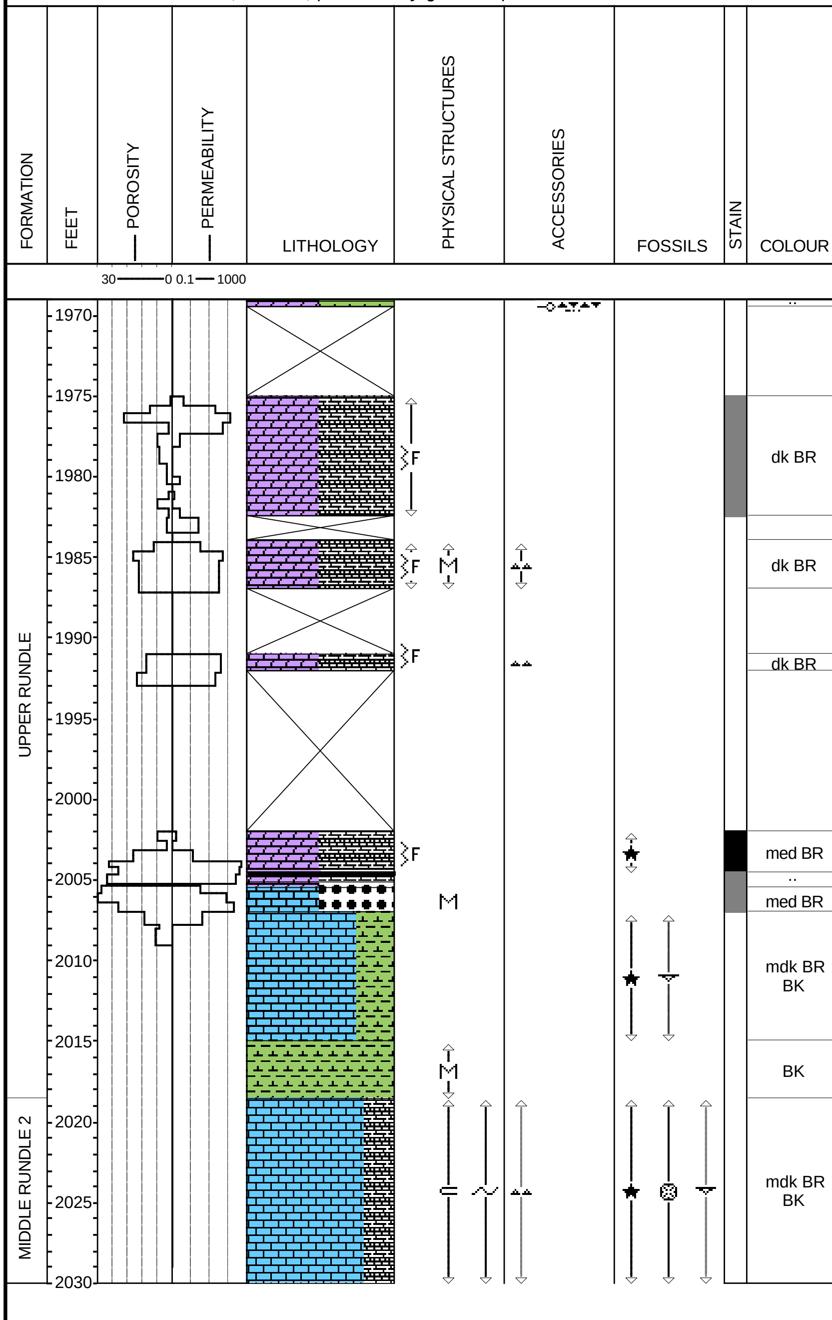
C-048-K 094-P-05

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1969.0-1975.0ft.; Cut: 6.0ft.; Rec'd: 0.5ft.
Core #2: 1975.0-1984.0ft.; Cut: 9.0ft.; Rec'd: 7.5ft.
Core #3: 1984.0-1991.0ft.; Cut: 7.0ft.; Rec'd: 3.0ft.
Core #4: 1991.0-2002.0ft.; Cut: 11.0ft.; Rec'd: 1.5ft.
Core #5: 2002.0-2030.0ft.; Cut: 28.0ft.; Rec'd: 28.0ft.

3.375 inch core; slabbed; poor to very good shape.



REMARKS

Rubble ?brecciated, cherty DOLOMITE, abundant flecks "Granny Smith" apple green SHALE.

DOLOSTONE: micro- to coarsely crystalline interbedded mudstone and skeletal wackestone/packstone; ?fractured; porosity poor, mostly vugs of indeterminate origin; trace skeletal moldic.

DOLOSTONE: Microcrystalline mudstone, barren; with horizons of dark grey and white CHERT. Some fractures lined with pale green clays - ?karst fill.

Mostly rubble. DOLOSTONE: Microcrystalline mudstone, barren; cherty. Hints of green clay on fracture/bedding surfaces.

DOLOSTONE: Micro- to finely crystalline; interbedded mudstone and (lesser amounts) of crinoidal wackestone/packstone; poor to fair skeletal-moldic porosity in skeletal units. Fractures lined with "Granny Smith" apple green SHALE.

DOLOSTONE: Microcrystalline; mudstone; barren.

DOLOSTONE: Finely crystalline skeletal packstone.

LIMESTONE: Coarse-grained, well sorted crinoidal packstone.

Interbedded (75:25): (1) LIMESTONE, mudstone, in beds 6 to 12 inches thick, mudstone to rare wackestone; and (2) SHALE, finely laminated; black in beds 1 - 4 inches thick, generally barren.

Black; barren.

Lime Mudstone with interbeds of crinoidal mudstone/wackestone; and MUDSTONE, calcareous, black (about 20%). Trace dark grey CHERT. Syringopora sp.

Canterra et al Thetlaandoa

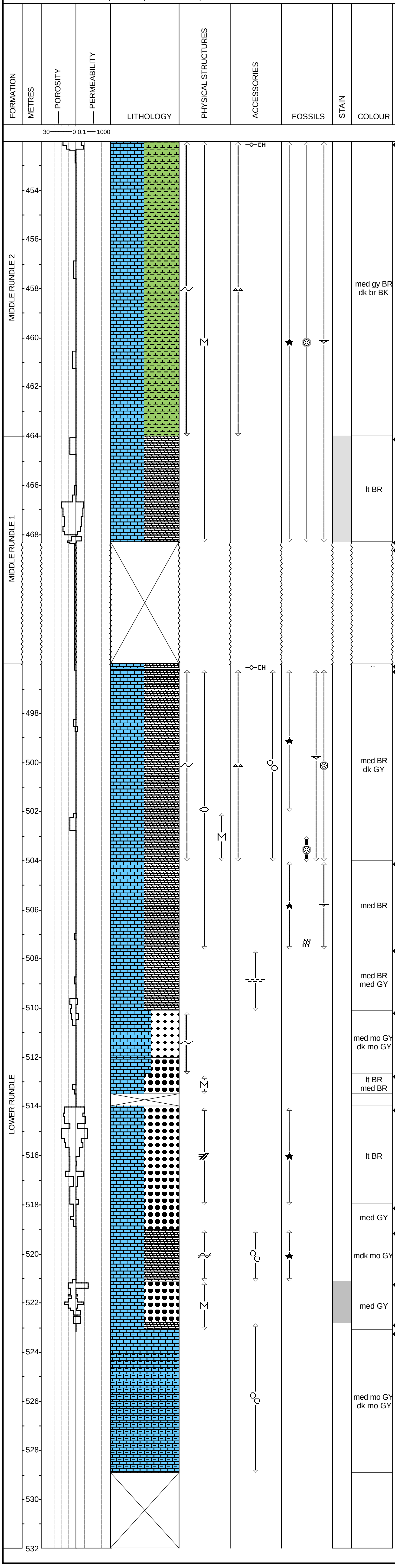
D-084-K 094-P-06

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #3: 496.00-505.00m, Cut 9.00m; Rec'd: 9.00m
Core #4: 505.00-514.00m, Cut 9.00m; Rec'd: 8.50m
Core #5: 514.00-523.00m, Cut 9.00m; Rec'd: 9.00m
Core #6: 523.00-532.00m, Cut 9.00m; Rec'd: 5.90m

3.375 inch core; slabbed; excellent shape.



REMARKS

LIMESTONE: Cyclical succession of (1) LIMESTONE, mudstone, featureless, pure, with less than 5% comminuted skeletal debris; and (2) SHALE, laminated. Breaks usually distinct, not gradational. Less than 5% dark grey CHERT nodules.

LIMESTONE: Mudstone, though probably a calcsiltite; fewer chale interbeds; nest and odd stringers of coarse skeletal debris.

Essentially the same environment as overlying but less argillaceous and very slightly coarser-grained.

Lost core.

Drilled interval.

Lime Mudstone; dark brown very finely laminated; contains 35% nodules of tan and medium grey CHERT.

Lime Mudstone, with 10% stringers and thin beds of calcareous SHALE; bedded nodular texture throughout. Sparse fauna. Basal metre a horn coral mudstone. Few nodules grey CHERT with brown rims. Tight.

Medium brown, lacks shake beds. 50% mudstone, remainder interbedding of mudstone with stringers, nests and individual beds of coarse-grained crinoidal mudstone/wackestone and rare packstone. Single Syringopora sp.

LIMESTONE: Crudely medium bedded mudstone and bioclastic mudstone/wackestone and rare, coarse-grained packstone. Beds 10-25 cm thick.

Interbedded (~60:40): (1) LIMESTONE, nodular to bedded nodular, argillaceous mudstone/wackestone; punctuated by several 10 - 20cm beds of (2) coarse-grained crinoidal PACKSTONE (?grain flows), also common stringers of bioclastic debris. Tight.

Light - medium brown, coarse-grained, well-sorted skeletal packstone, grading upsection to calcsiltite.

Light brown coarsening upward succession of well-sorted skeletal packstone. A few stringers of coarse crinoid debris.

Medium grey, homogeneous calcsiltite (packstone).

Bedded nodular to nodular argillaceous lime mudstone/wackestone, becoming more wackestone/packstone in basal metre; tight.

Coarsening upward from calcsiltite (packstone) to coarse-grained, well-sorted packstone.

Nodular/bedded medium grey mudstone; tight.

Scattered coarse skeletal debris. Classic nodular texture. Mottled medium-drak grey. Tight.

Amoco et al Thetlaandoa

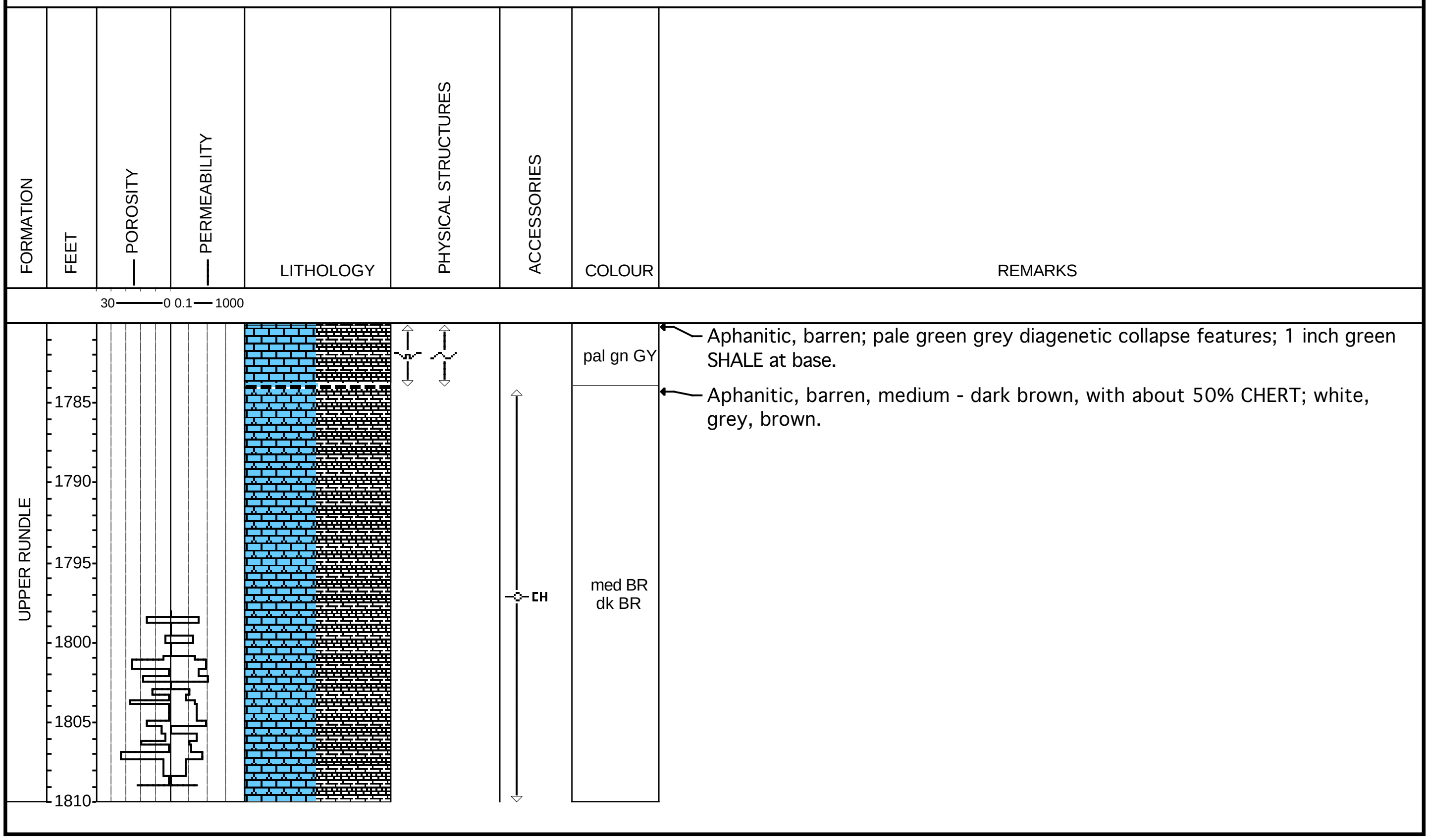
A-083-G 094-P-06

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1780.0-1798.0ft.; Cut: 18.0ft.; Rec'd: 18.0ft.
Core #2: 1798.0-1810.0ft.; Cut: 12.0ft.; Rec'd: 12.0ft.

4 inch core; slabbed; good shape.



Wincan et al Thetlaandoa

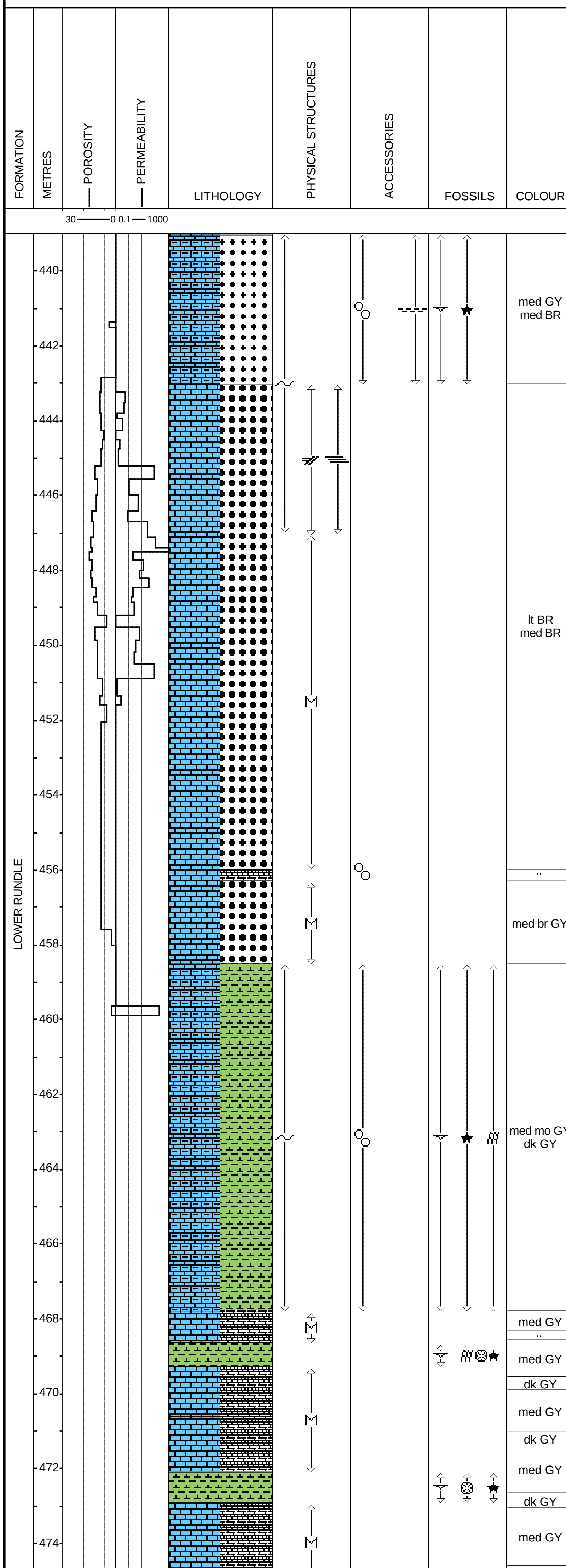
D-057-C 094-P-11

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 439.00-457.00m; Cut: 18.00m; Rec'd: 18.00m
Core #2: 457.00-475.00m; Cut: 18.00m; Rec'd: 18.00m

3.375 inch core; slabbed; excellent shape. ?Two metres off-depth.



REMARKS

Medium grey to brown, bedded to bedded-nodular appearance; predominantly wackestone to packstone, rarely mudstone with coarse skeletal material. Calcareous shale bands.

Predominantly fine-grained; very well sorted calcarenites (packstone to ?grainstone); few intervals interlaminated with dark brown mudstone, no burrowing; few layers with coarse burrows. Almost no recognizable skeletal components. High energy environment. Oil stain.

Bedded nodular mudstone/wackestone as in 439.00 - 443.00m.

Vaguely bedded; very well sorted, coarse-grained skeletal packstone.

Nodular argillaceous mudstone/wackestone, intercalated with calcareous SHALE. Mottled medium to dark grey.

Lime mudstone (75%), medium grey medium bedded and SHALE (25%), black, carries most fauna (Syringopora sp).

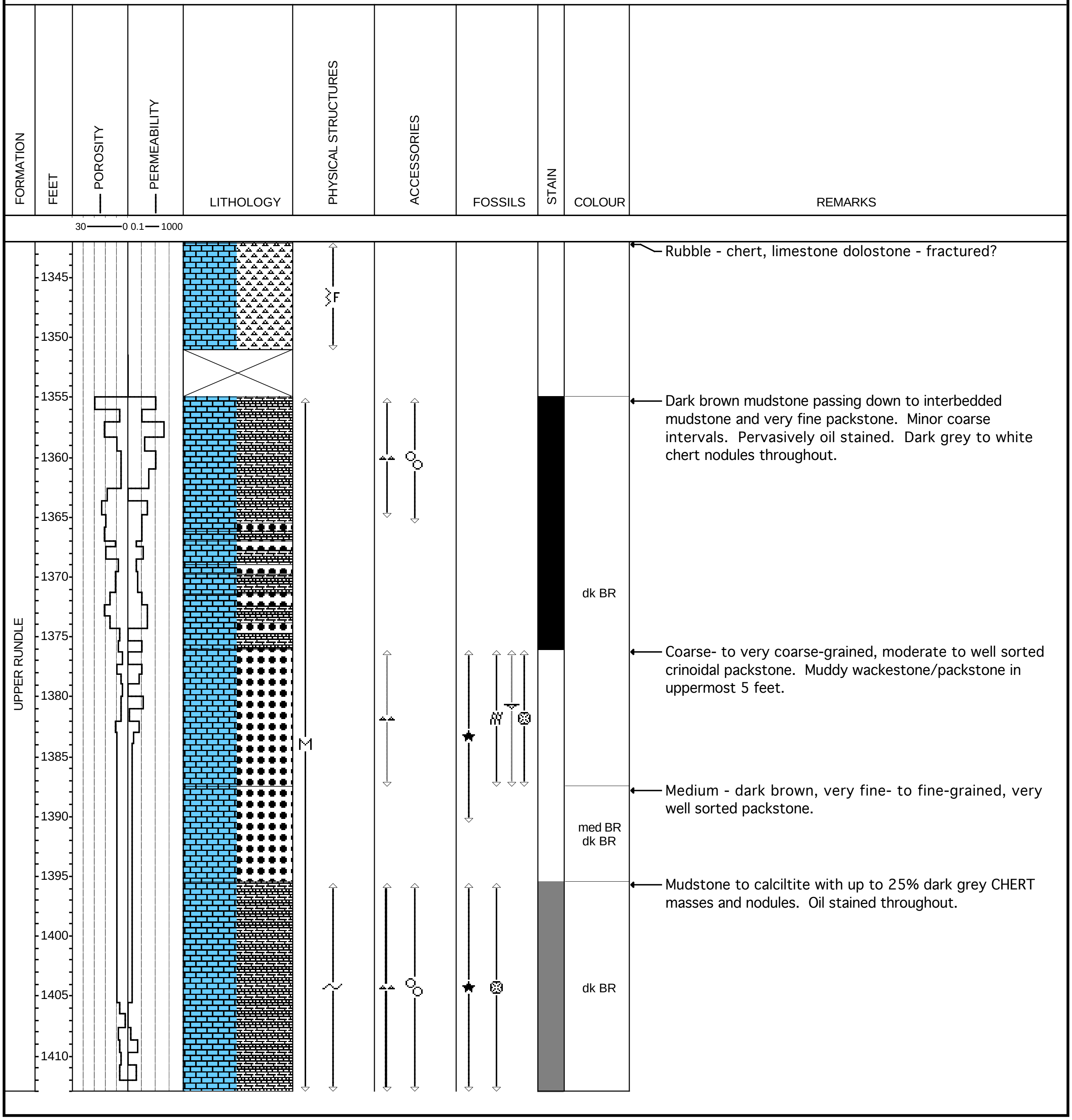
Ammin Thetlaandoa

D-037-C 094-P-11

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1342.0-1349.0ft.; Cut: 7.0ft.; Rec'd: 0.25ft.
Core #2: 1349.0-1351.0ft.; Cut: 2.0ft.; Rec'd: 1.0ft.
Core #3: 1355.0-1413.0ft.; Cut: 58.0ft.; Rec'd: 58.0ft.



Mobil Etset

D-035-E 094-P-11

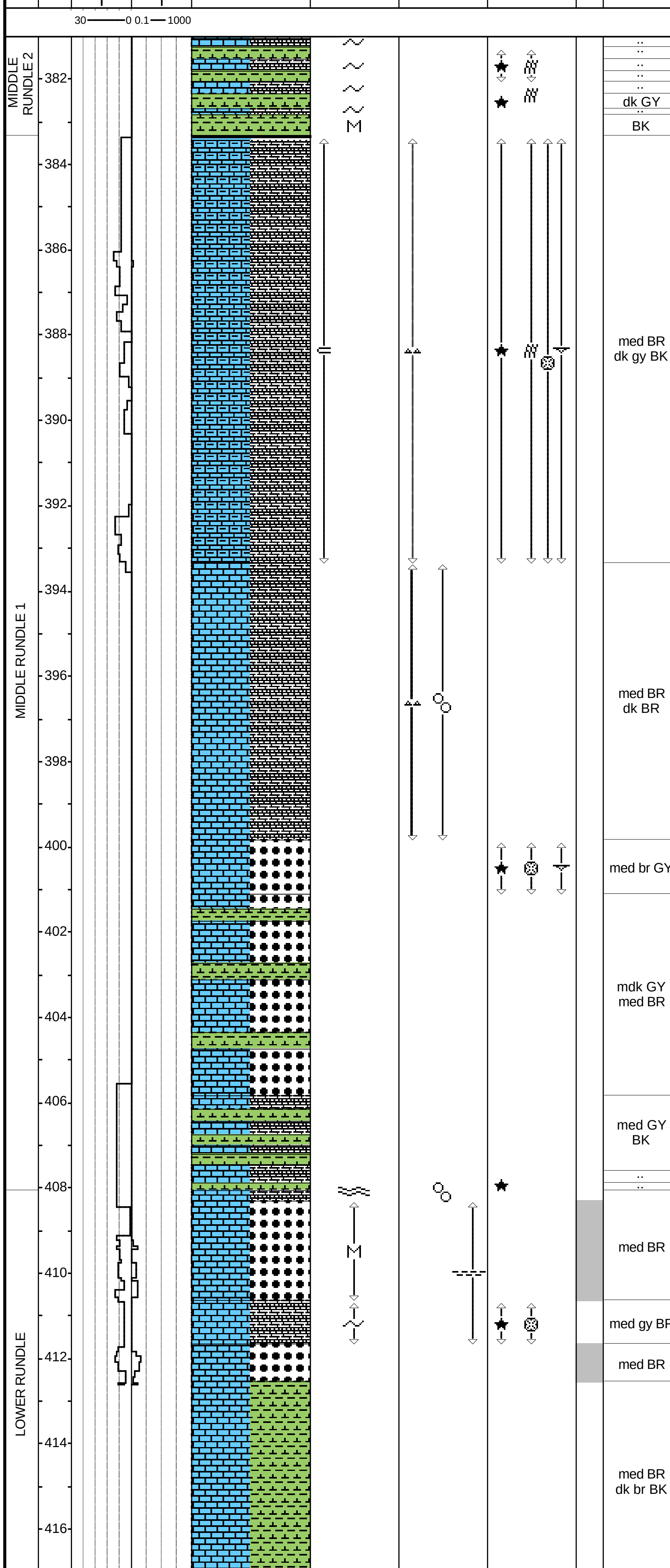
Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 381.00-399.00m; Cut: 18.00m; Rec'd: 18.00m
Core #2: 399.00-417.30m; Cut: 18.30m; Rec'd: 18.30m

3.375 inch core; slabbed, pristine. Oddly boxed, no tops indicated.

FORMATION	METRES	POROSITY	PERMEABILITY	LITHOLOGY	PHYSICAL STRUCTURES	ACCESSORIES	FOSSILS	STAIN	COLOUR	REMARKS



Interbedded (50:50); mudstone/wackestone; in 10 - 20cm beds; and SHALE, laminated; in wisps and bands up to 2cm thick; about 10% coarse skeletal debris.

Black; rare coarse skeletal debris.

Variably argillaceous; interbedded mudstone/wackestone, in beds ranging from wispy laminae to 30cm. Carries coarse skeletal debris; burrows in muddier units. Bedded to banded with some minor black chert nodules.

Medium - dark brown, aphanitic mudstone, barren; about 20% nodules and masses black CHERT.

Coarsening upward, stacked skeletal sands grading from well sorted, very fine-grained packstone to poorly sorted, coarse-grained packstone/wackestone.

Grain flows (packstone/wackestone) interbedded with platy fissile calcareous shale. Basal bed is very coarse crinoidal packstone/grainstone.
Med-dark grey and brown.

Interbedded (50:50): Dense, barren, mudstone in 5 - 10cm bands; and SHALE, calcareous in 2 - 5cm bands.

Interbedded mudstone/wackestone in thin, wavy bands and SHALE, dark grey, calcareous; bedded nodular texture.

Well sorted, medium brwon, fine-grained packstone, oil stained.

Mudstone/wackestone with shale interbeds; tight.

Fine- to coarse-grained medium brown, crinoidal packstone, as above.

Interbedded, well-bedded, aphanitic mudstone, barren bands 10 - 20cm thick; and calcareous MUDSTONE, laminated, barren; in beds 5 - 10cm thick.

Sun Cdn Sup Thetlaandoa

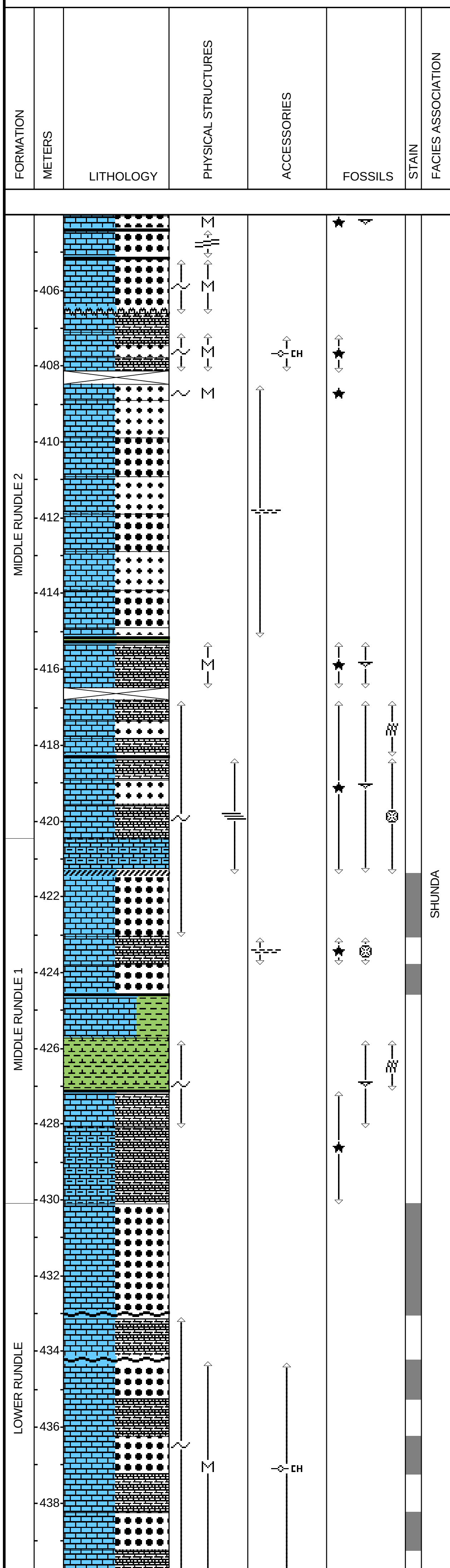
D-033-A 094-P-11

Date Logged: May, 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1 404.00-408.50 m Cut: 4.50 m Rec'd: 4.10 m 3 boxes
Core #2 408.50-416.80 m Cut: 8.30 m Rec'd: 8.00 m 6 boxes
Core #3 416.80-425.80 m Cut: 9.00 m Rec'd: 9.00 m 6 boxes
Core #4 425.80-435.00 m Cut 9.20 m Rec'd: 9.20 m 7 boxes
Core #5 435.00-440.00 m Cut: 5.00 m Rec'd: 4.85 m 4 boxes

3.375-inch core; slabbed; immaculate shape; 1.5 m off depth.



REMARKS

Medium brown; poorly sorted, coarse grained skeletal packstone with 20% very coarse skeletal debris.

Well sorted, fine-grained packstone, in basal 20 cm planar (low angle) cross-bedded with interbeds of very coarse-grained packstone.

Coarse to very coarse-grained, fair to well sorted packstone.minor wackestone/packstone; all mud-supported.

Medium brown, aphanitic, dense mudstone, massive to nodular, with minor coarse skeletal debris. Calcareous mudstone beds.

Laminae of black SHALE; a few bands with coarse crinoidal debris.

As in interval 407.30-408.10 m.

Light to medium brown, interbedded fine- to coarse-grained, well sorted packstone with wackestone. Basal metre essentially very fine-grained packstone; and upper two metres as well. Minor, wispy, black SHALE laminae.

Dark brown-black, barren, finely laminated.

Dull dark greenish-grey, ?argillaceous, massive mudstone; basal 0.25 m crudely bedded calcareous mudstone, slightly fissile.

Interbedded, pure, dark brown mudstone/wackestone with crinoidal debris and black, argillaceous lime mudstone, laminated. Basal contact unconformable, with 1 cm relief.

Interbedded, banded (1) LIMESTONE, mudstone to wackestone, scattered coarser skeletal debris and (2) LIMESTONE, argillaceous, black, finely laminated. Shaly bands thinner than lime bands.

Medium brown; massive, homogeneous calsiltite (packstone), ?pervasively bioturbated, upper metre oil stained.

Medium brown, aphanitic and dense mudstone.

Medium brown; mudstone at base passing to oil-stained calcsiltite in upper half.

Interbedded (75:25) (1) LIMESTONE, aphanitic mudstone, dark brown, homogeneous; barren; and (2) MUDSTONE?SHALE, black, finely laminated. Even-bedded, banded fabric.

Black, finely laminated; even-bedded, lime content increases in basal 30 cm.

Aphanitic mudstone; dark brown; indistinctly interbedded with very similar slightly argillaceous lime mudstone.

As above, banded appearance.

Very well sorted calsiltite (packstone), homogeneous, no fossil debris; oil stained throughout. Basal contact at 1 cm thick, jet black SHALE, finely laminated.

Medium brown; few argillaceous stringers; base at 3 cm thick black shale, as above.

Poorly defined shoaling upwards cycles: (1) LIMESTONE, dark brown, aphanitic mudstone, massive and homogeneous with hints of bioturbation; minor black SHALE interbeds, shoaling to (2) LIMESTONE, medium brown massive calcsiltite (packstone), oil-stained.

Nodules and irregular masses of black chert occur in former lithology.

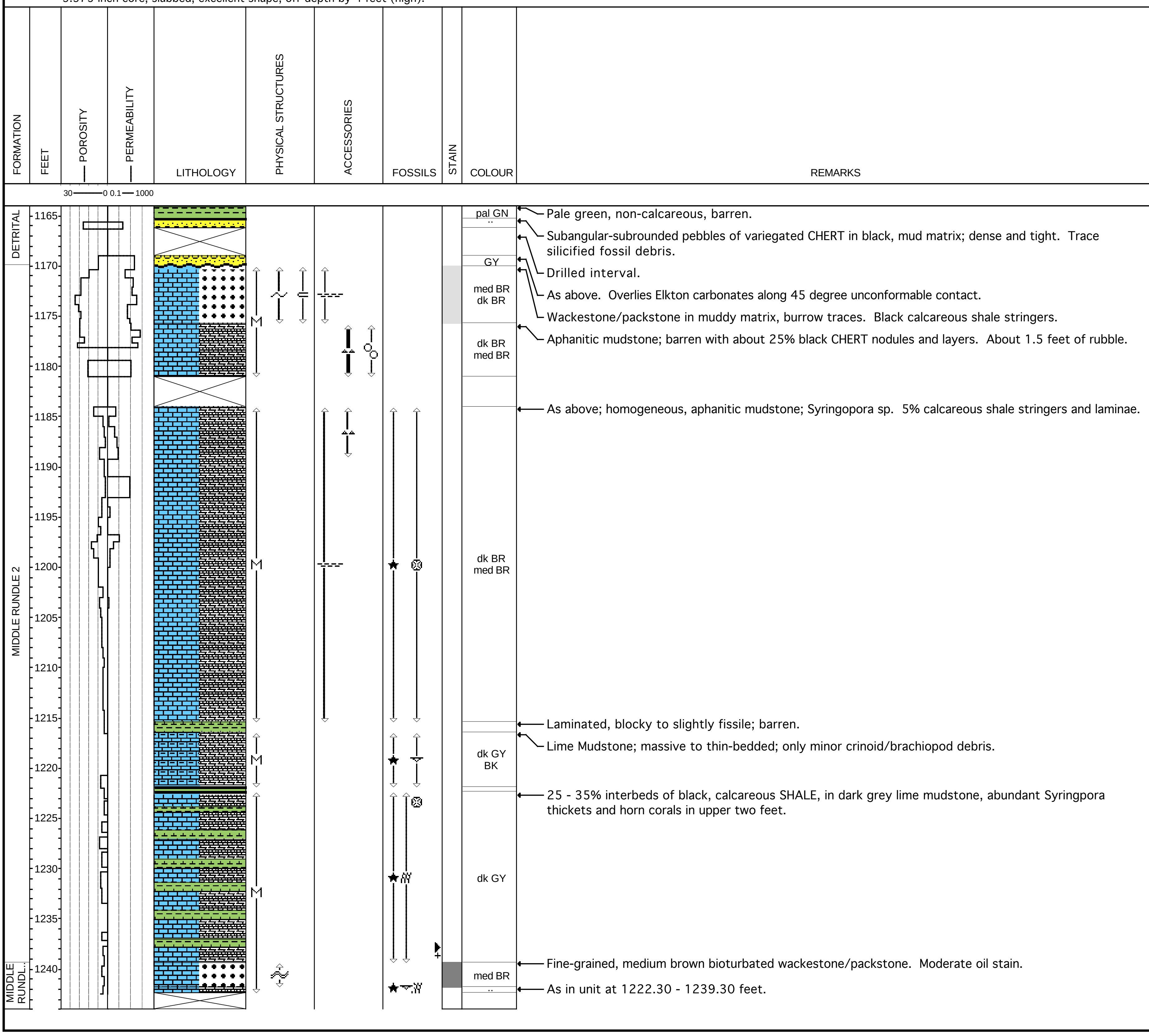
Ammin HBOG Etset
C-058-F 094-P-11

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1164.0-1167.0ft.; Cut: 3.0ft.; Rec'd: 2.25ft.
Core #2: 1169.0-1184.0ft.; Cut: 15.0ft.; Rec'd: 12.0ft.
Core #3: 1184.0-1244.0ft.; Cut: 60.0ft.; Rec'd: 60.0ft.

3.375 inch core; slabbed; excellent shape; off-depth by 4 feet (high).

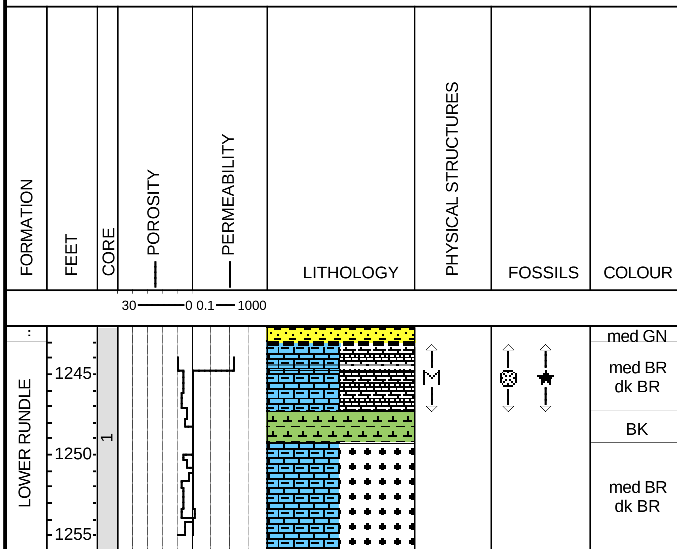


Amoco et al Wildboy

B-068-J 094-P-11

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.



REMARKS

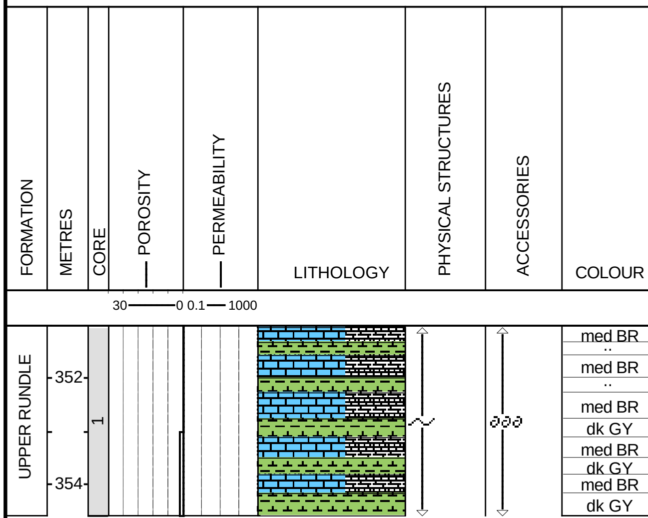
- Detrital - chert pebbles to cobbles on green mudstone matrix.
- Interbedded mudstone and horn coral wackestone; some interbeds of crinoidal wackestone/packstone; dense.
- Thin-bedded to laminated, black calcareous shale, barren; about 10% thin interbeds of lime mudstone.
- Medium to dark brown, fine-grained wackestone/packstone with interbeds of thin-bedded LIMESTONE.

Gulf Petitot

D-083-L 094-P-12

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.



REMARKS

Interbedded lime mudstone, some crinoidal, and dark grey calcareous shale. Up to 10% coarse skeletal debris. Open marine shelf.

Mobil Etset

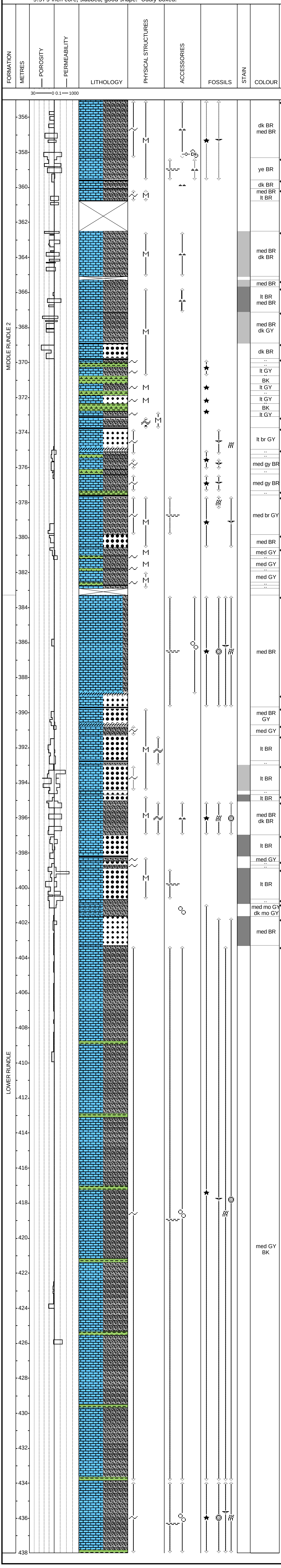
D-014-I 094-P-12

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 355.00-362.50m; Cut: 7.50m; Rec'd: 5.80m
Core #2: 362.50-365.30m; Cut: 2.80m; Rec'd: 2.60m
Core #3: 365.30-383.30m; Cut: 18.00m; Rec'd: 17.60m
Core #4: 383.30-400.90m; Cut: 17.60m; Rec'd: 17.60m
Core #5: 401.30-419.20m; Cut: 17.900m; Rec'd: 17.90m
Core #6: 419.50-438.00m; Cut: 18.50m; Rec'd: 18.50m

3.375 inch core; slabbed; good shape. Oddly boxed.



REMARKS

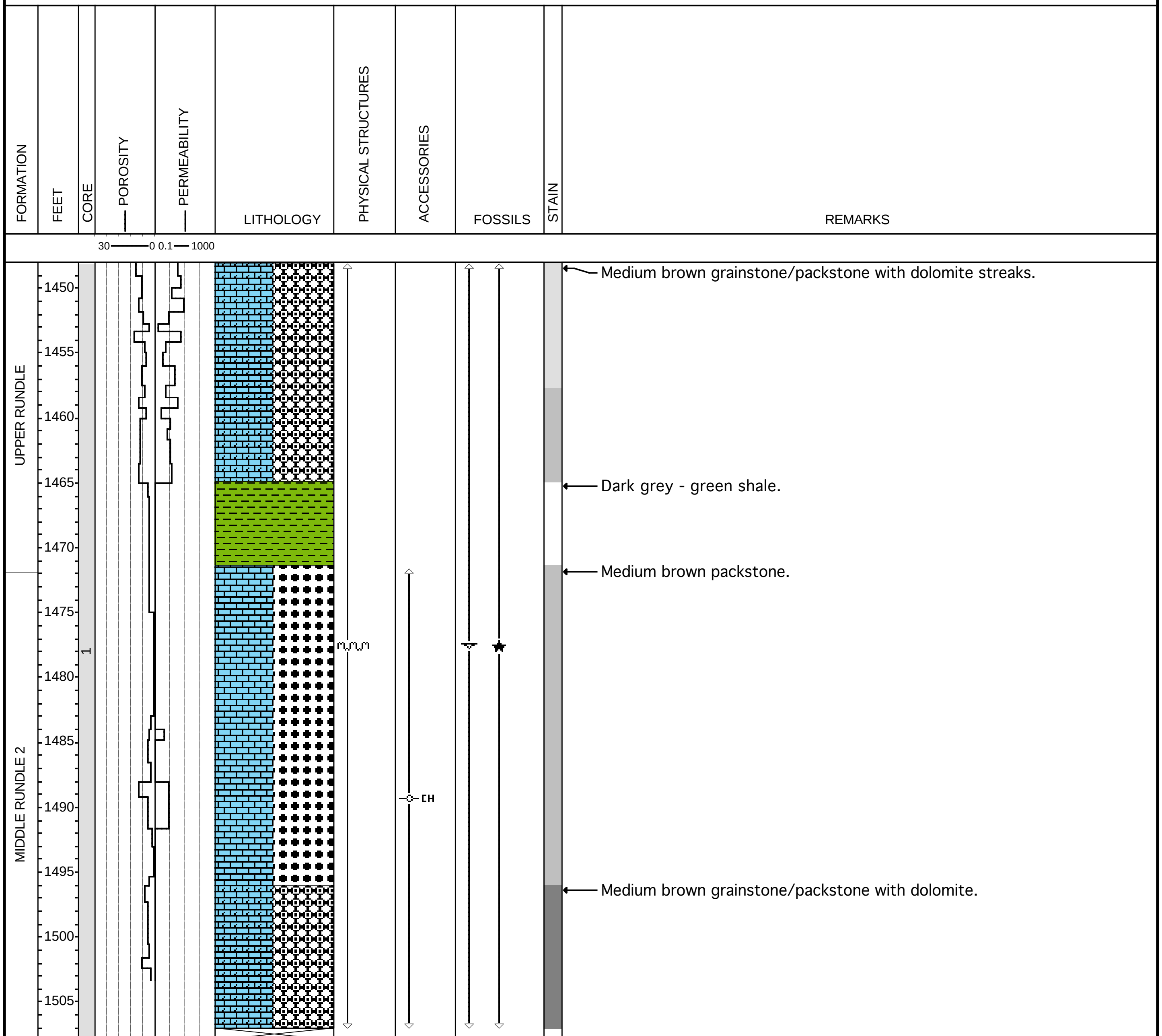
- Med-dark brown mudstone with trace coarser skeletal debris, generally featureless with few 5 - 10cm thick intervals which are finely laminated. Basal 50cm has common black CHERT nodules and bands. In part slightly dolomitic.
- Golden brown mudstone; only minor skeletal debris.
- Dark brown, aphanitic mudstone; finely laminated. Common grey CHERT, as above.
- Barren; tight.
- Medium to dark brown aphanitic mudstone; barren; in 15 - 20cm beds, interbedded with thin-bedded to finely laminated mudstone in 5 - 10cm bands. Some "dense" mudstone is heavily oil-stained.
- As in 362.50 - 365.10 metres, base rubble.
- Light to medium brown, barren, aphanitic mudstone with 50% layers and irregular masses of dark grey and white CHERT. In part heavily oil stained.
- Medium brown-dark grey, aphanitic, barren mudstone, interbedded pure massive and finely laminated units. Dark grey-dark brown CHERT. Oil stained where porous.
- Coarse-grained crinoidal packstone to muddy wackestone/packstone; well sorted; few argillaceous stringers at top. Tight.
- Interbedded (50:50): (1) SHALE, fissile, finely laminated, with interbeds of (2) LIMESTONE, as either fine interlaminae; irregular beds and stringers to 2cm thick; or massive 10 - 20cm thick interbeds. Bioturbated units are mudstone to fine crinoid wackestone. Tight.
- ?Slightly argillaceous; barren aphanitic mudstone.
- Light brown to grey, crudely bedded; coarsely crinoidal wackestone, wackestone/packstone; few irregular argillaceous stringers. Tight.
- LIMESTONE (80%), in irregular bands 20 - 30cm thick, mudstone to rarer wackestone; and SHALE/MUDSTONE (20%), thin bedded to finely laminated, barren. Near top, one 30cm bed of coarse-grained, well sorted skeletal packstone.
- Black, laminated; barren.
- Mudstone-wackestone with coarse skeletal debris, noticeably more argillaceous in upper 0.50m. Tight.
- Fine-grained skeletal packstone/wackestone in muddy matrix; fair to good sorting. Tight.
- Interbedded: LIMESTONE (65%), mudstone, barren; and SHALE (35%), finely laminated, calcareous, black. Tight.
- Regular thin to medium layers separated by, laminated, calcareous SHALE/LIMESTONE (10%). Bedded nodular appearance. Limes are mudstone/wackestone with coarser skeletal material in argillaceous beds. Tight.
- As above but wackestone/packstone. Tight.
- Poor to well sorted skeletal packstone.
- Medium grey, mudstone, dense.
- Light brown, fine-grained, well sorted, skeletal packstone. No coarse skeletal debris.
- Fine to coarse packstone, coarsest at base. In part oil stained.
- Coarse- to very coarse-grained crinoidal packstone; fair sorting, abrupt base and top.
- Medium brown lime mudstone, grades to shale at base. Limes carry about 10% black CHERT nodules with medium brown rinds.
- Light brown, fine- to coarse-grained packstone, fair to good sorting; hints of planar bedding near base. No visible porosity.
- Fair sorted, fine grained packstone.
- Interbedded fine- and coarse-grained, well-sorted skeletal packstone/grainstone. Oil stained.
- Dense aphanitic mudstone.
- "Coalesced" nodular to bedded nodular texture; crinoidal.
- Interbedded lime mudstone and coarse medium brown wackestone/packstone, some oil stain.
- Lime mudstone (80 - 90%), interbedded with SHALE (10 - 20%), calcareous, bedded nodular texture. Some interbeds of coarse, fairly sorted crinoidal packstone.

Ammin Owl

B-017-H 094-P-12

Date Logged:

Logged by: PETREL ROBERTSON CONSULTING LTD.



Mobil N. Petitot

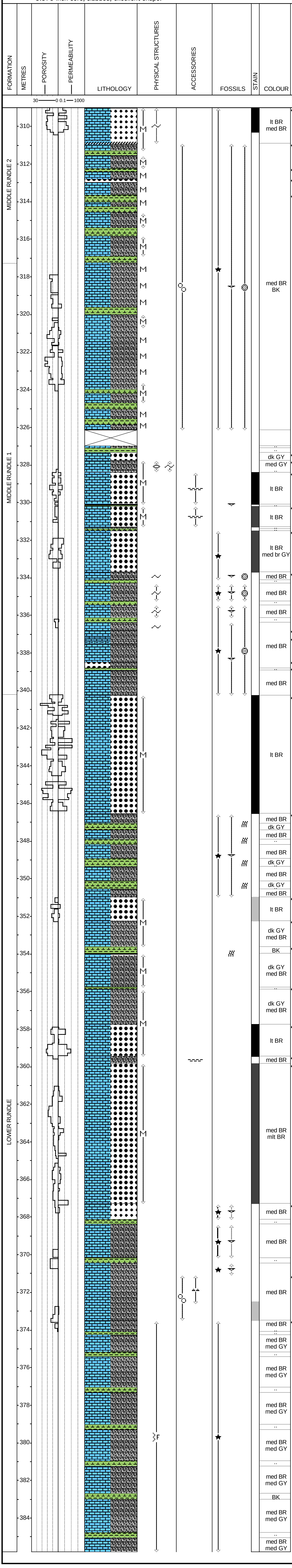
D-097-C 094-P-13

Date Logged: May 1999

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 309.00-327.00m; Cut 18.00m; Rec'd: 17.15m
Core #2: 327.00-345.00m; Cut 18.00m; Rec'd: 18.00m
Core #3: 345.00-363.00m; Cut 18.00m; Rec'd: 18.00m
Core #4: 363.00-381.00m; Cut 18.00m; Rec'd: 18.00m
Core #5: 381.00-385.80m; Cut 4.80m; Rec'd: 4.80m

3.375 inch core; slabbed; excellent shape.



REMARKS

- Light - medium brown skeletal wackestone/packstone, mainly fine-grained; carries single Syringopora sp. No visible porosity.
- Interbedded: (1) LIMESTONE, mudstone/wackestone to wackestone/packstone, former in fairly distinct beds, latter can be interbedded with SHALE, laminated to thin-bedded, slightly calcareous. Argillaceous bands give the whole a bedded appearance. Bedded nodular texture, with (rare) nodular interbeds. Occasional thin to medium homogeneous packstone units. Tight appearance.
- Calcareous mudstone unit.
- Coarse-grained packstone band.
- Calcareous laminated black mudstone with spiriferid brachiopods
- Coarsening upward; fine- to coarse-grained, well sorted packstone. Tight.
- Interbedded pure mudstone; nodular mudstone, with 1 - 2cm thick stringers of coarse, poorly sorted crinoidal packstone. Tight.
- Light brown, very fine- to fine-grained skeletal packstone, well-sorted; minor shaley lamina give hint of bedding.
- Fine- to medium-grained crinoidal packstone; near base with thin interbeds of calcareous SHALE.
- Basal two-thirds is fine-grained, well-sorted packstone; upper third poorly sorted wackestone/packstone, tight; purer mudstone (interbeds).
- Interbedded (80:20): Medium brown lime mudstone to wackestone in thick beds or intercalated with shale; some muddy packstone also present; and SHALE, finely laminated to thin bedded, calcareous, black. Tight. Arbitrary basal contact.
- Similar to above, but less fossiliferous; banded appearance.
- Argillaceous band.
- Single bed of coarse-grained, muddy packstone/wackestone. Tight.
- Laminated, fissile calcareous shale.
- Well sorted, fine-grained skeletal packstone, few argillaceous stringers, few interbeds of muddy wackestone/packstone. No sedimentary structures or bioturbation. Heavily sampled and disarranged. Heavily oil stained.
- Interbedded (60:40): LIMESTONE, mudstone/wackestone, generally in distinct 5 - 30cm bands; and SHALE, finely laminated. Distinctive banded appearance.
- Very well sorted calcsiltite to fine calcarenite (packstone); light brown, lightly oil stained.
- Interbedded dark grey mudstone, fine- to coarse-grained wackestone/packstone with shaley stringers; basal portion mudstone, passing to wackstone/packstone and mudstone units.
- Finely laminated, fissile, black.
- As above.
- Coarse- to very coarse-grained crinoidal packstone; heavily oil-stained.
- Interbedded (90:10): Mudstone, minor wackestone and SHALE, fissile. Banded appearance.
- Very coarse-grained, well-sorted packstone; abrupt contacts; tight; and distinctly interbedded mudstone (calcsiltite) and various types of well-sorted packstone to ?grainstone ranging from fine-grained to grits. Hints of planar bedding in some units. Few argillaceous stringers and interbeds.
- Interbedded (90:10): In 5 - 30cm thick bands; mudstone/wackestone at base passing to wackestone/packstone at top; and SHALE in stringers and wispy laminae.
- Banded nodular texture, pure mudstone, to calcsiltite in basal metre, 15 - 20cm bands separated by argillaceous laminae.
- Interbedded (90:10) with a distinct banded look: Medium brown mudstone to rare wackestone and SHALE; stringers and laminae. Dense and tight. Trace vertical fractures.

CARBONATE
APPLECORES

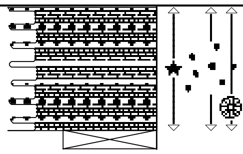
PC IMP CLARKE

C-094-L 094-J-09

Date Logged: May 11, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

FORMATION	FEET	CORE	TEXTURE	FOSSILS	COLOR	REMARKS
			framestn, boundstn, bafflestn, rudstn, floatstn, grainstn, packstn, wackestn, mudstn			
DEBOLT	1890 1895	1			BK	Bituminous, black, skeletal mudstone grading to skeletal wackestone. Some thin bedding visible. Bioclasts - mostly crinoids, rare large syringoporids, and rare rugose corals. No visible porosity.

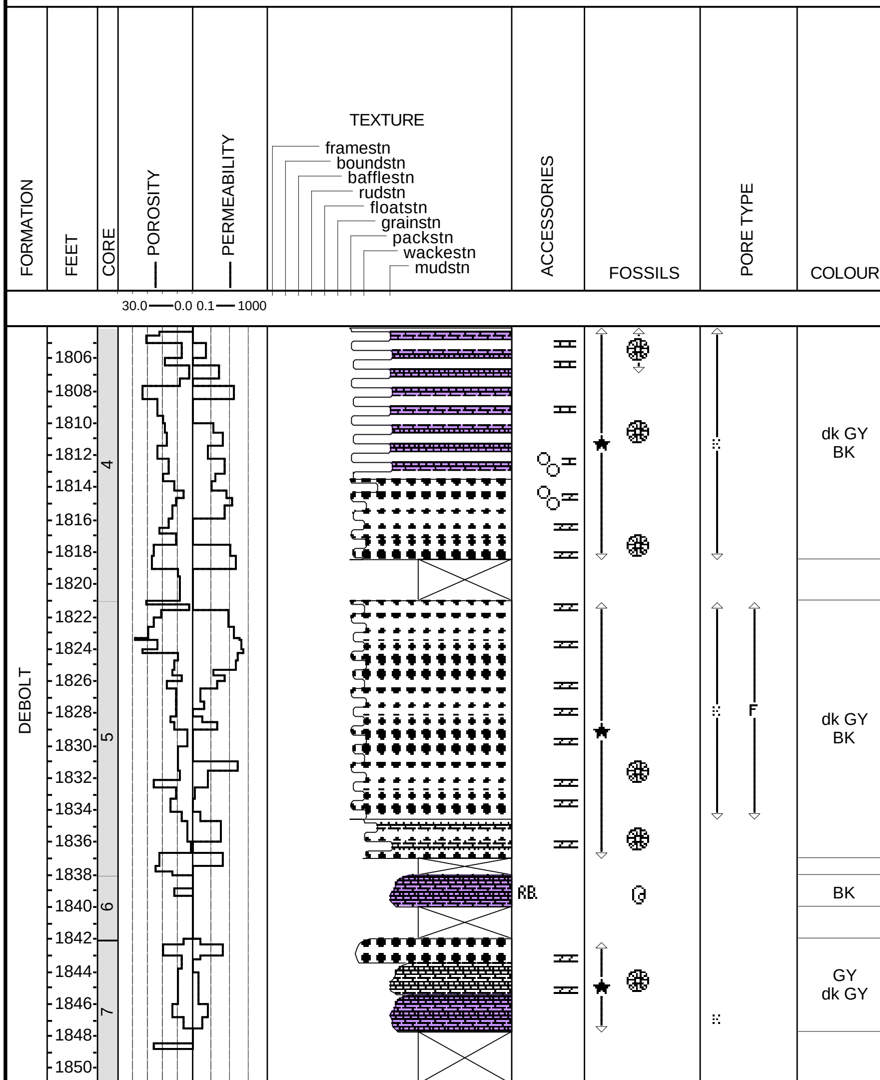


PEX ET AL CLARKE

D-083-I 094-J-10

Date Logged: May 12, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.



REMARKS

Bituminous, calcareous, skeletal dolomudstone to dolowackestone. Bioclasts - mostly crinoids, rare rugose corals. Rare tan nodules, fossiliferous, sucrosic in part. Rare vertical fractures occluded with white calcite. Scattered pinpoint porosity.

Dolomitic limestone to calcareous dolostone. Bituminous, skeletal wackestone grading to packstone. Bioclasts - crinoids and rare rugose corals. Scattered pinpoint porosity.

Dolomitic limestone to calcareous dolostone. Bituminous skeletal wackestone to packstone. Bioclasts - mostly crinoids, rare rugose corals. Rare vertical fractures mostly occluded with white calcite. Scattered pinpoint porosity.

Dolomitic limestone to calcareous dolostone. Bituminous skeletal mudstone to wackestone. Bioclasts - crinoids, rare Lithostrotion and horn corals. Rare vuggy porosity (>1 cm).

Core very fragmented. Bituminous dolomudstone. Rare ostracods visible. No visible porosity.

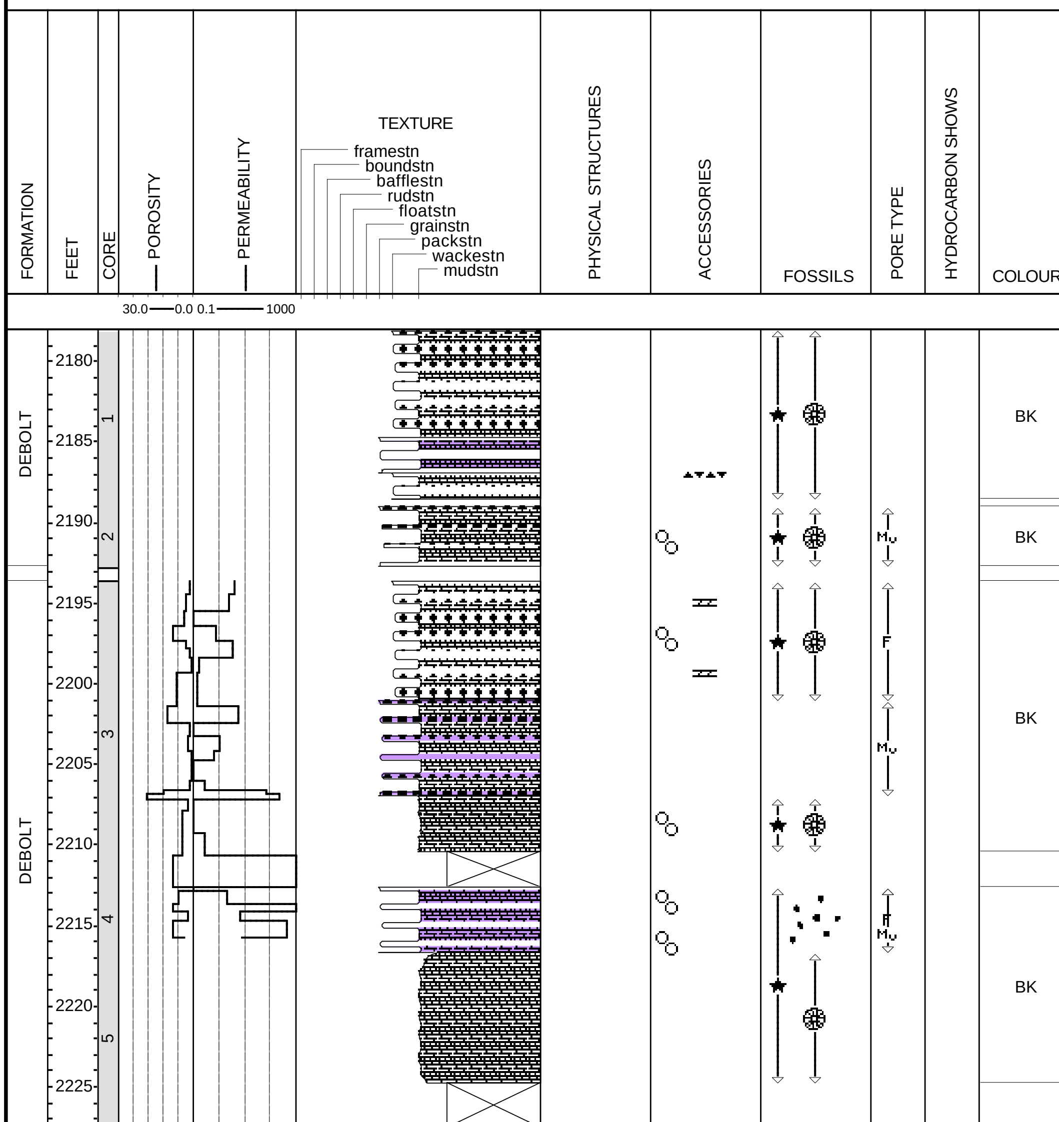
Dolomitic skeletal packstone grading downwards to skeletal dolomudstone. Variably bituminous. Bioclasts - mostly crinoids, rare rugose corals. Minor scattered pinpoint porosity.

PEX ET AL CLARKE

02/a-065-G 094-J-10

Date Logged: May 8, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.



REMARKS

Black, bituminous skeletal mudstone to wackestone. Dolostone between 2184.7-2186.9'. Bioclasts - mostly crinoids, rugose corals (some large). Locally brecciated and cemented with coarse white calcite/dolomite @2186.9'. No visible porosity.

Limestone to calcareous dolostone. Bituminous, black, skeletal mudstone with thin skeletal wackestone-packstone interbeds. Bioclasts - crinoids, rugose corals (some large). Locally nodular. Very small vuggy/moldic porosity.

Bituminous, black, skeletal mudstone to wackestone, locally dolomitic, locally nodular. Bioclasts - crinoids and large rugose corals. Rare verical fractures.

Medium interbedded, bituminous, black, skeletal dolomudstone (as above) and bituminous dolopackstone. Scattered pinpoint and vuggy (0.5-2 cm) porosity in dolopackstone.

Thin to medium bedded, black, bituminous, skeletal mudstone. Bioclasts - small crinoids and rare Lithostrotion corals. Locally nodular. No visible porosity.

Bituminous, black, skeletal dolomudstone to dolowackestone (locally calcareous). Bioclasts - mostly crinoids, rare syringoporids. Locally nodular. Rare moldic and pinpoint porosity. Core is fractured (horizontally and vertically) and is rubble in places.

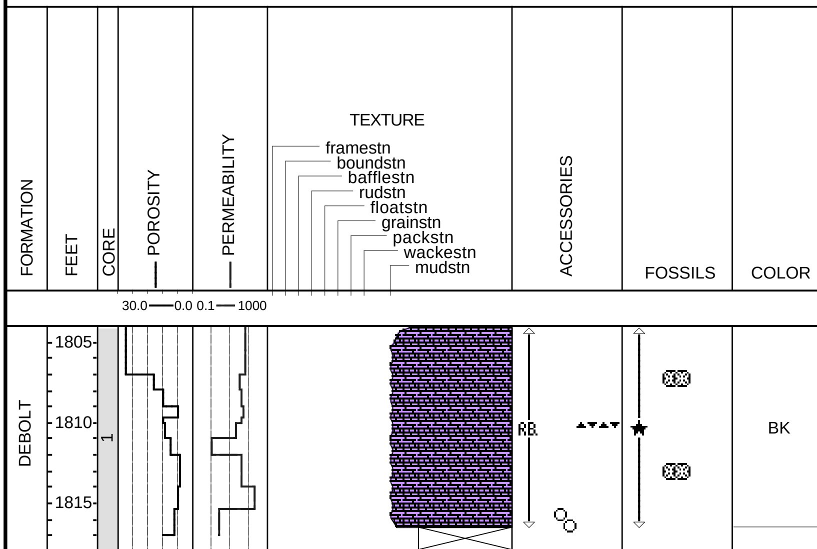
Bituminous, black, skeletal mudstone. Bioclasts - mostly crinoids, rare large rugose corals. Core is fractured and rubble in places.

GULF STATES IMP CLARKE LAKE

C-064-I 094-J-10

Date Logged: May 11, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.



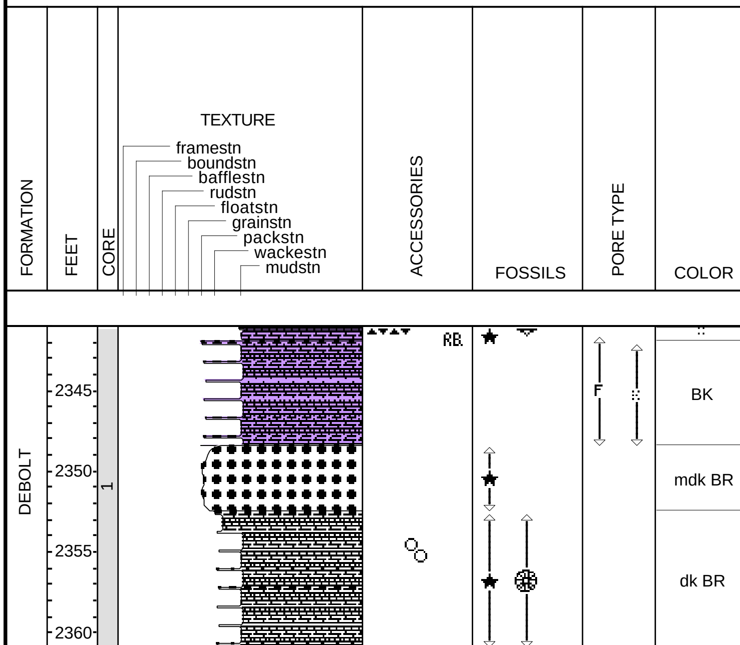
Bituminous, black, skeletal dolomudstone, slightly calcareous locally. Bioclasts - mostly very small crinoids, rare digitate corals. Rare nodules at the base of core. Brecciated interval between 1810-1810.5', interparticle porosity occluded with white calcite cement. Scattered pinpoint porosity, very rare intraskeletal/moldic porosity. Core is 40% rubble, some fractures observable in core and are mostly vertical.

Pacific Fort Nelson No. 2

A-019-G 094-J-10

Date Logged: May 11, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.



REMARKS

Argillaceous, black, sparsely fossiliferous mudstone. Bioclasts - very small crinoids and brachiopods? Few verical fractures.

Unusual brecciated interval, appears to be an unconformity with irregular, sharp upper and lower contacts. Clasts are rimmed by orange and green staining. Original lithology - dolomudstone?, very altered. Core is mostly rubble, some fracture porosity visible, interparticle sparry dolomite cement.

Bituminous, locally nodular, black dolomudstone (slightly calcareous locally) with rare thin dolopackstone interbeds. Bioclasts - small crinoids. Scattered pinpoint porosity, minor fractures.

Medium to dark brown packstone, skeletal in part (small crinoids visible). Sharp lower contact, gradational upper.

Bituminous, dark brown, locally dolomitic, skeletal mudstone grading locally to skeletal wackestone. Bioclasts - crinoids and rare rugose corals. Rare large black nodules that look cherty. Rare isolated vugs occluded with white calcite cement. No visible porosity.

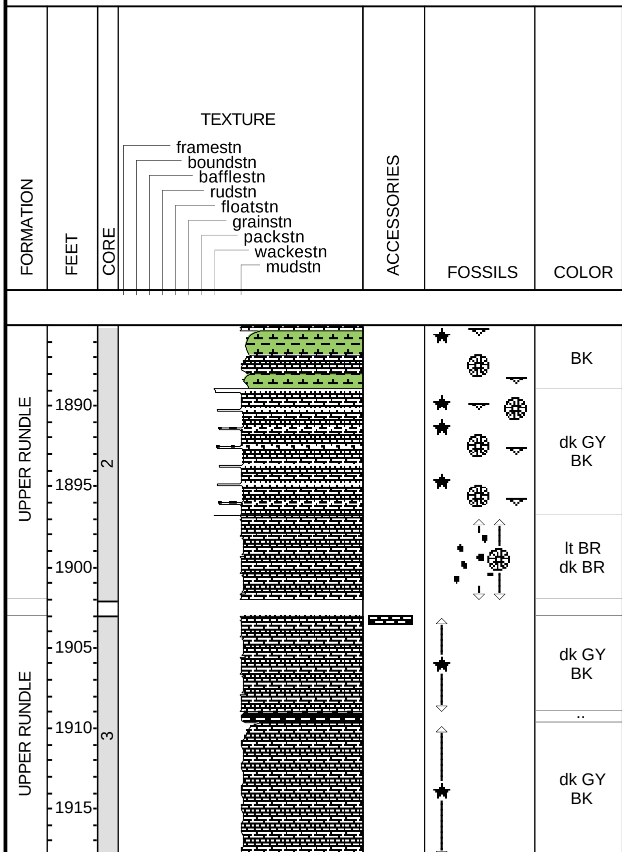
GULF STATES CHUATSE CREEK

B-014-I 094-J-16

Date Logged: May 11, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Core not slabbed.**



REMARKS

Bituminous/argillaceous, black, sparsely fossilierous mudstone. Bioclasts - brachiopods and very small crinoids.

Black, calcareous shale with sparse brachiopods.

Bituminous/argillaceous, black, fossiliferous mudstone. Bioclasts - large rugose corals. No visible porosity.

Black, calcareous shale with sparse brachiopods.

Dark grey to black, argillaceous/bituminous, skeletal mudstone to wackestone. Bioclasts - mostly small crinoids, rare brachiopods, Lithostrotion and large rugose corals. Some thin bedded visible. No visible porosity.

Thin to medium bedded, fossiliferous mudstone, beds alternate light and dark brown. Bioclasts - rugose corals (some large), and rare syringoporids. Rare vertical fractures occluded with calcite. No visible porosity.

Thin to medium bedded, bituminous/argillaceous, sparsely fossiliferous mudstone. Beds alternate dark grey and black. Bioclasts - crinoid ossicles. Bituminous laminite @ 1903.2', 1.5 cm thick. No visible porosity.

Black shale.

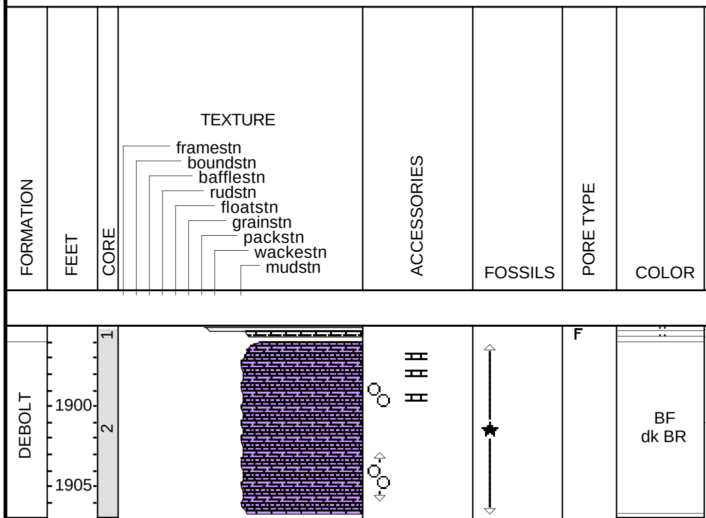
Dark grey to black, sparsely fossiliferous mudstone. Bioclasts - crinoids. No visible porostiy.

MISSION HOFFARD

B-006-A 094-J-16

Date Logged: May 8, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.



Conglomerate consists of poorly sorted, rounded chert clasts in a sandy, greenish clay matrix.

Bituminous mudstone? Upper surface of carbonate is irregular and has a 2-4 cm thick whitish reaction rim. Vertical fractures in core.

Tan to dark brown dolomudstone (slightly calcareous in upper 3.5') with rare crinoids. Increasingly nodular downwards. Nodules range from <1 cm to greater than width of core (3.5"), are cherty, mostly white, some white and black, some zoned, some are very irregular, and some are fractured. Core is locally fractured and rubble in places. Very coarse sparry dolomite and sulphides in a large vug at 1902.5'.

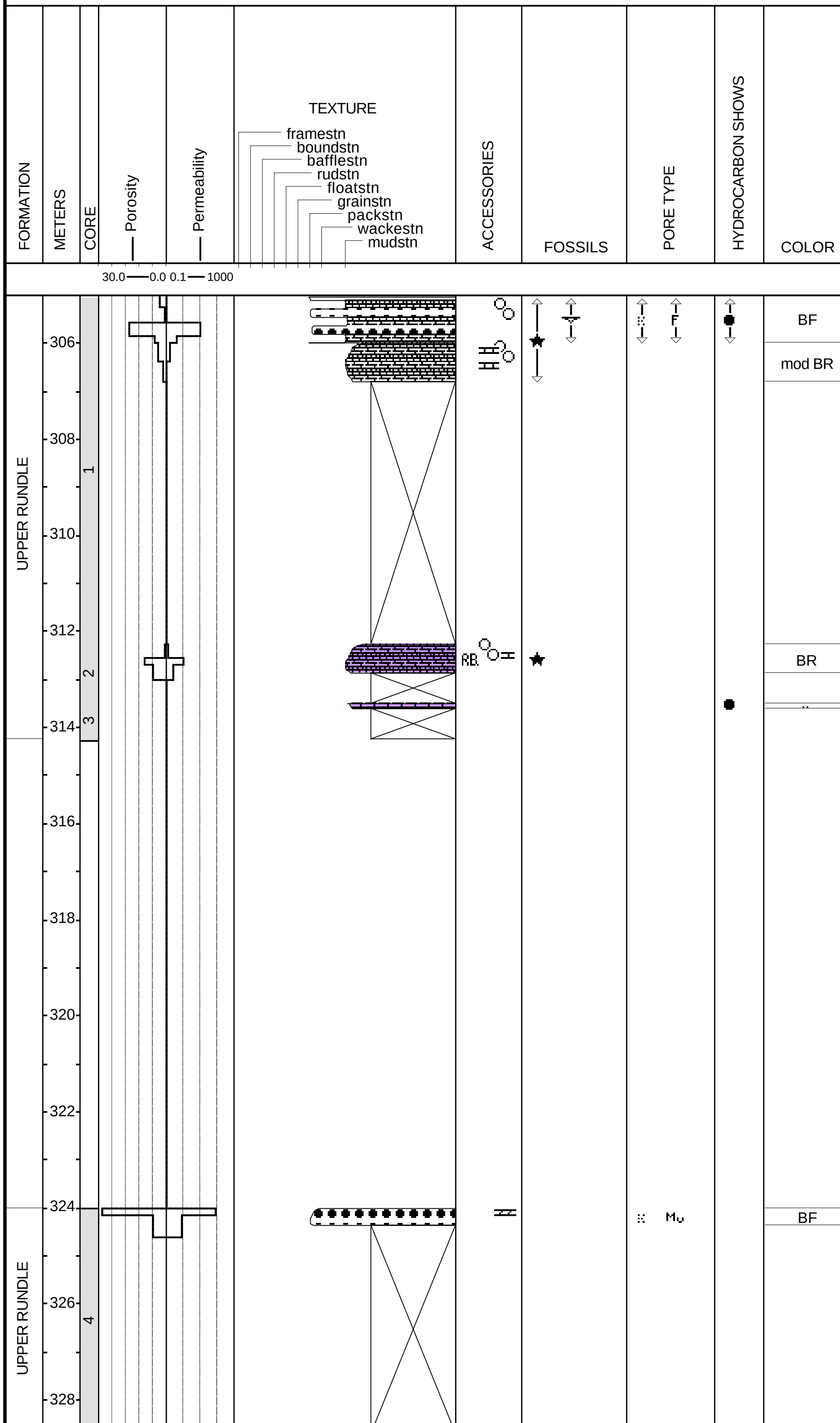
TEXACO PHILIS

D-079-G 094-O-16

Date Logged: May 12, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Core 1 very fragmented.**



REMARKS

Tan, packstone to mudstone, nodular at top, locally laminated at base. Bioclasts - mostly crinoids and rare brachiopods. Some scattered pinpoint porosity, rare partly open vertical fractures. Locally oil stained.

Medium brown, sparsely fossiliferous, calcareous dolomudstone. Bioclasts - crinoids. Rare white nodules. No visible porosity but core is broken vertically - open fractures?

Calcareous dolomudstone, mottled in part, rare white nodules, sparsely fossiliferous. Bioclasts - crinoids. No visible porosity but core is mostly rubble - possibly fractured.

White dolomudstone. No visible porosity. Spotty oil staining.

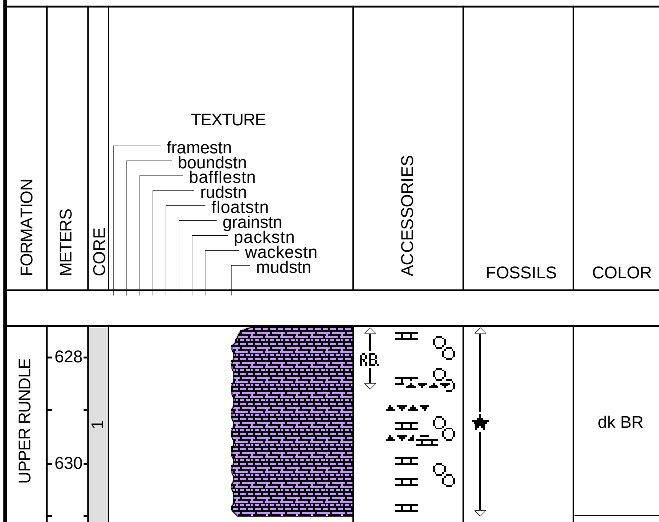
Thinly bedded, tan to light brown, dolomitic packstone. Scattered pinpoint and vuggy (up to 2.5 cm) porosity.

PENN WEST TSEA

C-043-J 94-P-5

Date Logged: May 11, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.



REMARKS

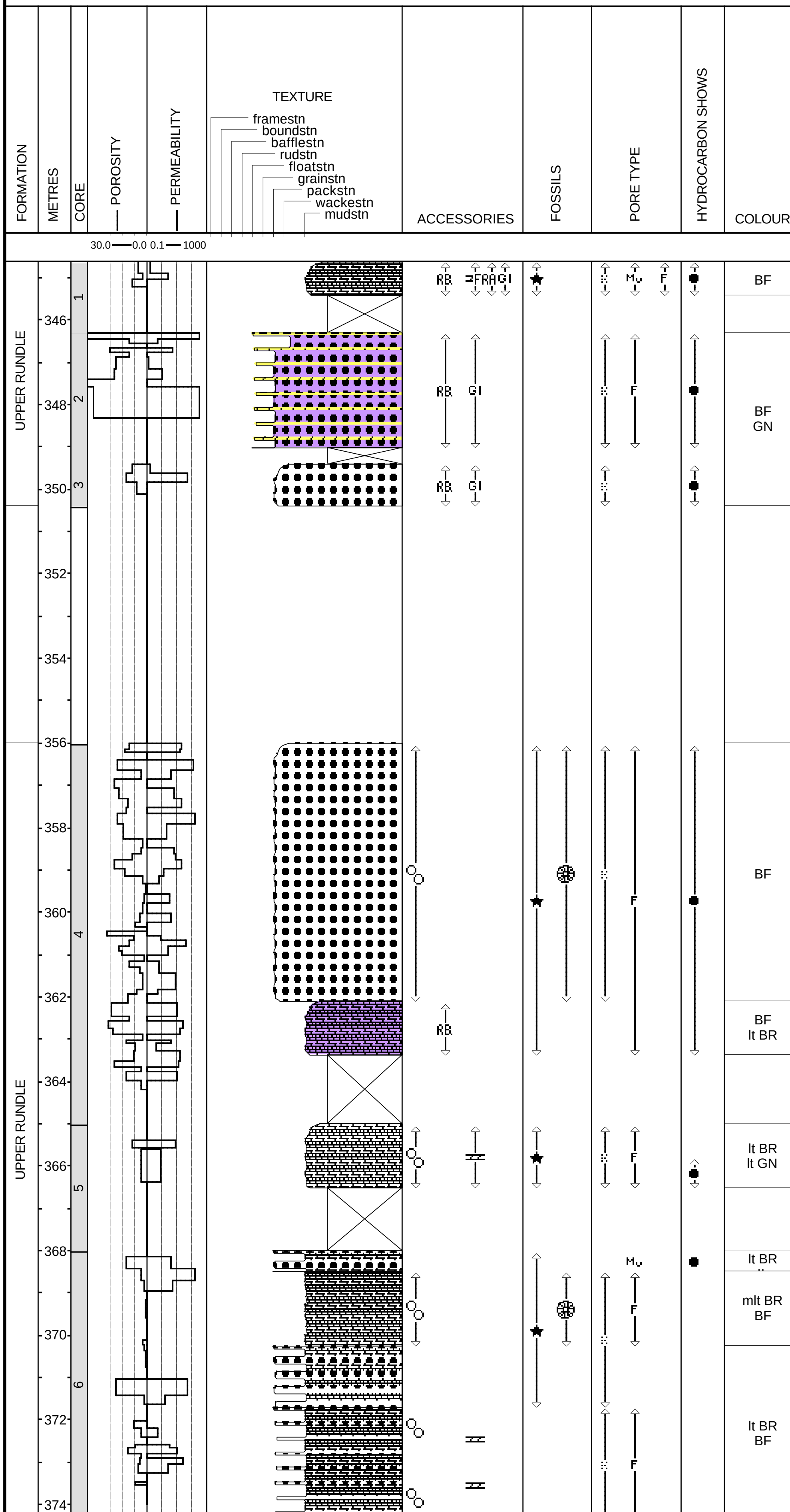
Dark brown, bituminous, very sparsely fossiliferous calcareous dolomudstone to dolomitic mudstone. Bioclasts - crinoids. Scattered dark grey nodules with a tan rim, some up to >10 cm diameter. Rare, thin, tan, irregular beds, elongate nodules? Locally brecciated and healed between 628.5 and 629.5 m. Trace fracture porosity visible but lots of rubble in box - open fractures?

CANTERRA WESTAR PETITOT

D-057-L 094-P-12

Date Logged: May 7, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.



Sparsely fossiliferous, dolomitic mudstone. Bioclasts - mostly small crinoids. Porosity - fractures, scattered pinpoint and small vugs, oil stained. Interval is mostly rubble and coated with green clay. Appears to be karst breccia.

Core mostly rubble, various lithologies present, many clasts coated in green clay. Lithologies include: 1) dolopackstone, locally calcareous, tan, porosity - scattered pinpoint, fracture, oil stained. 2) Sandstone with green clay clasts and lenses, possible cavern fill. 3) White and green laminated and massive clay, possible cavern fill.

Core mostly rubble, clasts coated with green clay. Packstone visible, skeletal in part, tan, scattered pinpoint porosity, oil stained.

Fairly homogeneous interval. Packstone - locally dolomitic, tan, skeletal in part, bioclasts - crinoids, rugose corals. Scattered pinpoint porosity and common vertical fractures. Light to heavy oil staining in uncleaned core intervals.

Core mostly rubble. Thinly bedded dolomudstone, tan and light brown, mottled in part, looks diagenetic. Sparsely fossiliferous, bioclasts - small crinoids. Vertical fractures, oil stained.

Thinly bedded, light brown, dolomitc mudstone with scattered nodules. Sparsely fossiliferous, bioclasts - small crinoids. Locally fractured, rare pinpoint porostiy. Lower 0.7 m is oil stained rubble, partly coated with green clay.

Mudstone to packstone, tan, light brown, and light grey, locally mottled - appears diagenetic. Skeletal in part, bioclasts - crinoids. Rare small vuggy porosity. Localy oil stained.

Sparsely fossiliferous, mottled and nodular, tan, light-medium brown, and light green mudstone. Bioclasts - crinoids, rare rugose corals. Scattered pinpoint porosity and fractures.

Thin to medium interbedded packstone and mudstone. Packstone - locally dolomitic, tan, white, skeletal in part, scattered pinpoint porosity. Mudstone - light brown, sparsely fossiliferous, crinoid bioclasts. Locally brecciated and dolomitized. Green clay in box.

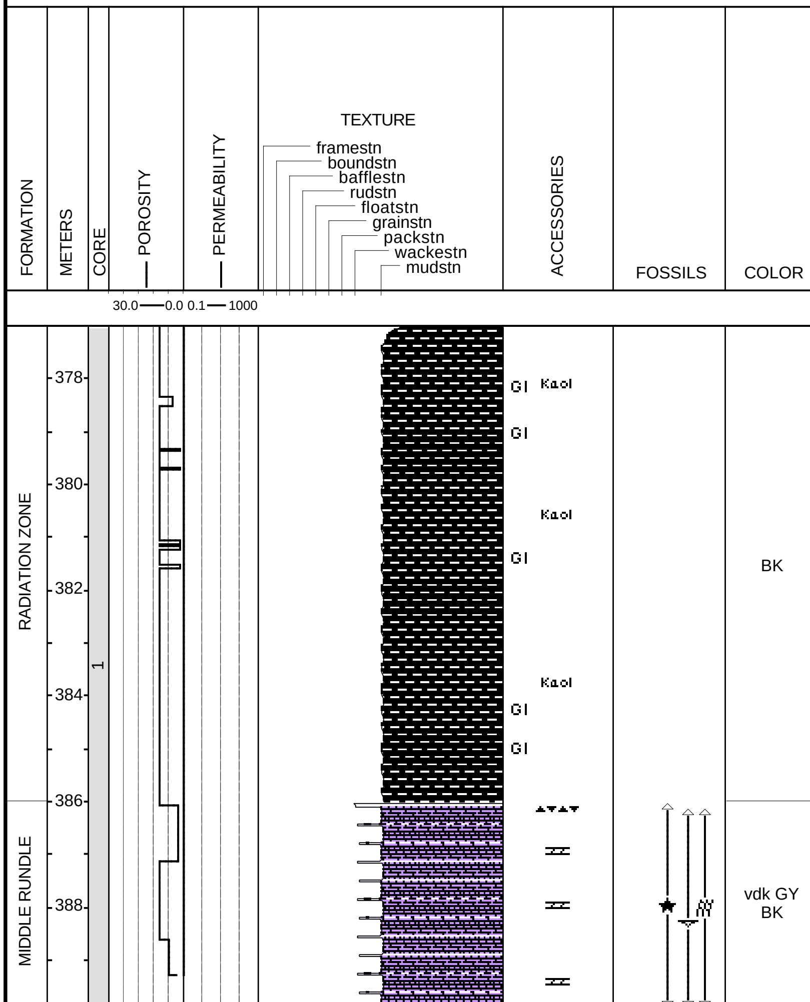
Core appears to be mixed in part. Mostly mudstone with packstone interbeds. Lithologies as above. Also minor bituminous, nodular, skeletal, slightly calcareous dolomudstone. Some pinpoint porosity and vertical fractures in interval.

MOBIL ETSET

D-055-H 094-P-12

Date Logged: May 11, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.



REMARKS

Spirit River - black shale with kaolinite and glauconite interbeds.

Bituminous, very dark grey to black, sparsely fossiliferous, locally dolomitic mudstone with rare thin skeletal wackestone interbeds. Bioclasts - crinoids (some still ariculated), fenestellid bryozoans, and rare brachiopods. Upper contact with the Cretaceous is brecciated over a 2cm interval. No visible porosity.

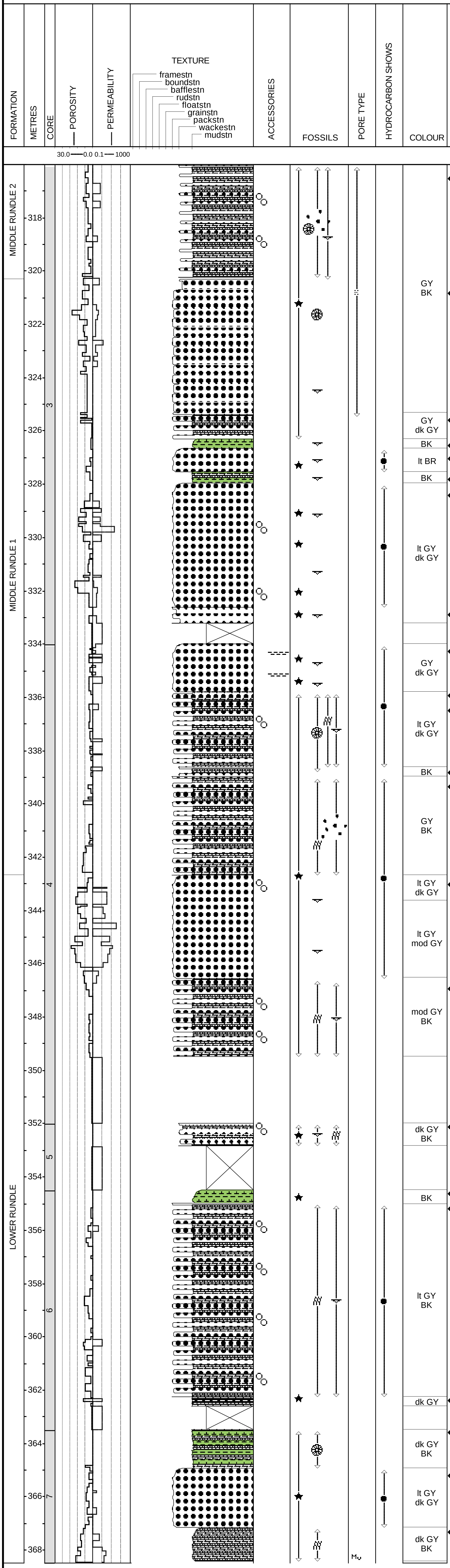
MOBIL N PETITOT

D-033-E 094-P-13

Date Logged: May 11, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **3.5 m off depth (too high)**



REMARKS

Laminated to medium bedded/nodular bedded/mottled, variably bituminous, grey to black, skeletal mudstone to wackestone. Bituminous content occurs generally as whispy microstylolites. Bioclasts - mostly crinoids, rarely articulated, rare rugose corals, minor brachiopods, and rare syringoporids. No visible porosity.

Laminated to medium bedded/nodular bedded/locally mottled, grey to black, skeletal wackestone to packstone (90% packstone). Bituminous content is variable and occurs as whispy microstylolites. Bioclasts - mostly crinoids (some still articulated), rare rugose corals, and rare brachiopods. Rare pinpoint/small vugggy porosity. Localized oil staining.

Thin to thickly interbedded skeletal packstone and mudstone with irregular bedding contacts. Grey to dark grey, some beds are slightly bituminous with whispy microstylolites.

Bituminous, black mudstone to calcareous shale (locally fissile), sharp contacts. Bioclasts - rare brachiopods.

Crinoidal packstone with scattered large ossicles, rare brachiopods. Some thin bedding, scattered whispy microstylolites. Rare vertical fractures occluded with white calcite. No visible porosity. Scattered oil staining.

Black, bituminous mudstone to calcareous shale (locally fissile) with rare brachiopods. Sharp lower contact, gradational upper. Tight.

Thin to medium bedded, locally nodular, variably bituminous, light to dark grey, skeletal packstone. Bituminous content occurs as whispy microstylolites. Bioclasts - scattered crinoids and brachiopods. No visible porosity, some beds oil stained (heavy in places).

Thin to medium bedded, light to dark grey, skeletal wackestone to packstone. Faintly mottled locally, variably argillaceous, scattered whispy microstylolites. Bioclasts - mostly crinoids, minor brachiopods. No visiible porosity.

Thinly bedded, mottled, and nodular, grey to dark grey skeletal packstone. Variably argillaceous/bituminous, whispy microstylolites common. Rare black, argillaceous interlaminae. Bioclasts - crinoids and minor brachiopods. No visible porosity. Local spotty oil staining.

Interlaminated to medium interbedded, dark grey, crinoidal wackestone-packstone and argillaceous/bituminous, black mudstone. Locally burrowed. No visible porosity.

Interlaminated to medium interbedded skeletal packstone and mudstone-wackestone. Packstone - locally nodular and mottled, light to dark grey, whispy microstylolites, crinoid bioclasts, no visible porosity, and locally oil stained. Mudstone-wackestone - dark grey to black, bioclasts include rugose corals, crinoids, fenestellid bryozoans, and brachiopods. No visible porosity.

Thinly interbedded: 1) black, bituminous mudstone to shale and 2) variably bituminous, dark grey to black, skeletal wackestone with crinoid and rugose coral bioclasts. No visible porosity.

Thinly interbedded: 1) Grey, skeletal mudstone to wackestone with crinoid and rare brachiopod bioclasts. No visible porosity. 2) Bituminous, black mudstone to shale (locally fissile). Bioclasts - crinoids, rare syringoporids, fenestellid bryozoans. No visible porosity. 3) Medium grey crinoidal packstone, locally burrowed. No visible porosity. Locally oil stained. Large vertical fractures through interval are occluded with white calcite, rare pinpoint porosity in cement.

Variably bituminous, light-dark grey and black crinoidal packstone. Scattered larger crinoid ossicles and brachiopods. Whispy microstylolites common, locally nodular, burrowed, and thin to medium bedded. No visible porosity. some beds have spotty to solid oil staining.

Thin to medium interbedded: 1) Medium grey, skeletal mudstone-wackestone, locally nodular and burrowed, bioclasts - crinoids, no visible porosity. 2) Black/dark grey, bituminous/argillaceous mudstone, bioclasts - crinoids and fenestellid bryozoans, no visible porosity. 3) Medium grey, skeletal packstone, locally nodular, bioclasts - crinoids and minor brachiopods, no visible porosity.

Bituminous/argillaceous, dark grey to black, mottled to nodular skeletal mudstone to wackestone. Bioclasts - crinoids, fenestellid bryozoans, and rare brachiopods. No visible porosity.

Black, calcareous shale, rare scattered crinoids, gradational lower contact.

Thin to medium interbedded and locally interlaminated: 1) dark grey, skeletal mudstone to wackestone. Bioclasts - mostly crinoids, rare brachiopods. Locally nodular and burrowed. No visible porosity. 2) Bituminous, black, mudstone with whispy microstylolites. Bioclasts - crinoids, fenestellid bbryozoans, and rare brachiopods. No visible porosity. 3) Light to medium grey, locally mottled and nodular, skeletal packstone. Bioclasts - mostly crinoids, rare brachiopods. No visible porosity. Spotty to solid oil stain in some beds.

Thin to medium interbedded: 1) Black shale. 2) Dark grey skeletal mudstone with crinoid bioclasts. No visible porosity.

Very thin to medium interbedded: 1) Black, bituminous mudstone to shale. 2) Dark grey, sparsely fossiliferous mudstone. Bioclasts - crinoids and rugose corals. One isolated vug ~1 cm diameter.

Light to dark grey, crinoidal packstone. Fining upwards, some thin to medium bedding visible, rare thin mudstone interbeds near top. Scattered whispy microstylolites, locally burrowed. No visible porosity. Patchy oil staining locally.

Laminated, thinly bedded, and mottled, bituminous/argillaceous, dark grey, brown, and black, sparsely fossiliferous mudstone. Bioclasts - crinoids and fenestellid bryozoans. Rare vugggy porosity near base associated with fractures.

CLASTIC
APPLECORES

Nexen Tsoo

C-13-H 94-O-4

Date Logged: June 25, 2009

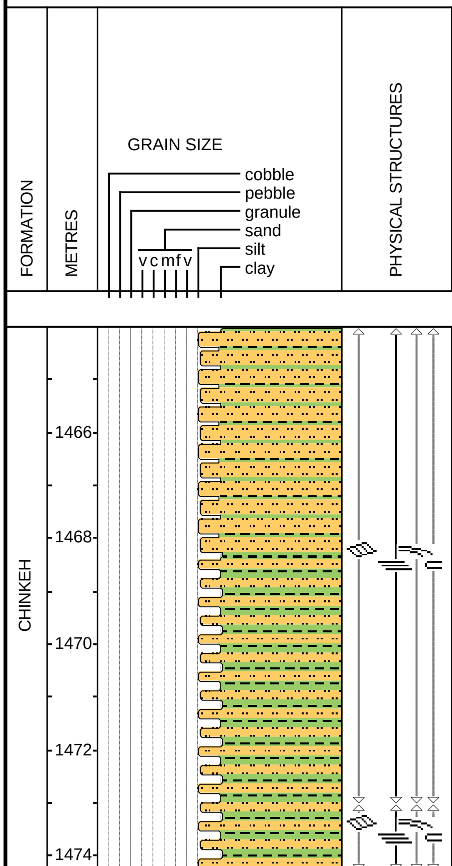
Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Core 2**

Interval: 1464–1474.5m, About 10.3 m recovered.

Core slabbed, somewhat dirty, not logged in detail

No core analysis.



REMARKS

1474.3 - 1464. Very finely laminated light grey siltstone and dark grey siltstone/shale. Minor horizontal burrowing observed. Siltstones commonly cross-laminated, with some climbing ripples. Occasional thicker (up to ~10 cm) siltstone beds with wavy, possible hummocky cross-stratification. Above 1468.4m, siltstone predominates and the rock becomes less friable.

Nexen Tsoo

C-13-H 94-O-4

Date Logged: June 25, 2009

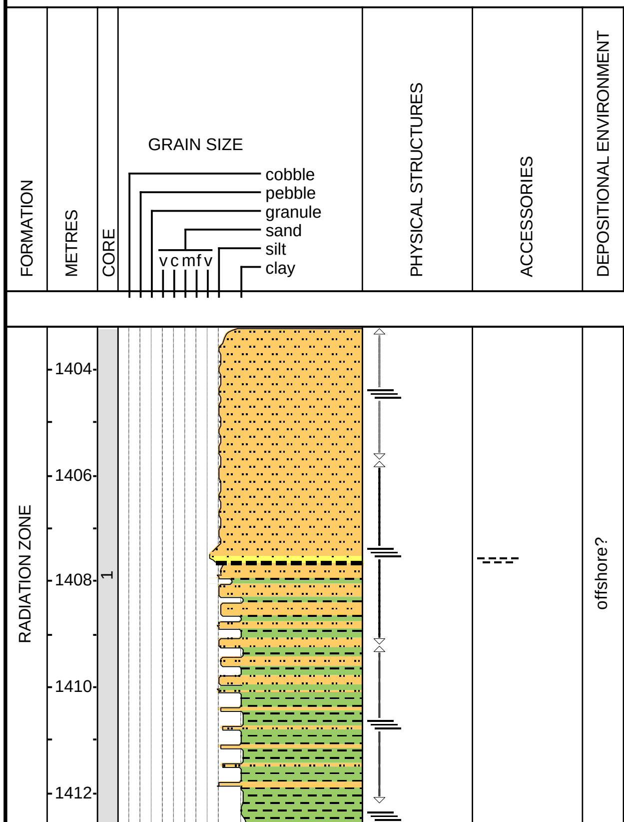
Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Core 1**

Cored Interval: 1403–1414.3, about 9.45 m recovered

No analysis

Core slabbed, but very dirty.



REMARKS

1407.25 - 1403.2. Dark grey siltstone, finely laminated to nearly massive in appearance. Occasional light grey siltstone beds up to ~20 cm thick in upper part.

1407.4-1407.25. Finely laminated, very fine grey, muddy sandstone with numerous shaly partings. Contact possibly sharp, but in rubbled zone.

1412.65-1407.4. Dark grey, massive mudstone rading upward into dark grey, finely laminated siltstone.

Chevron Lightning Patry

B-98-A 94-O-5

Date Logged: June 24, 2009

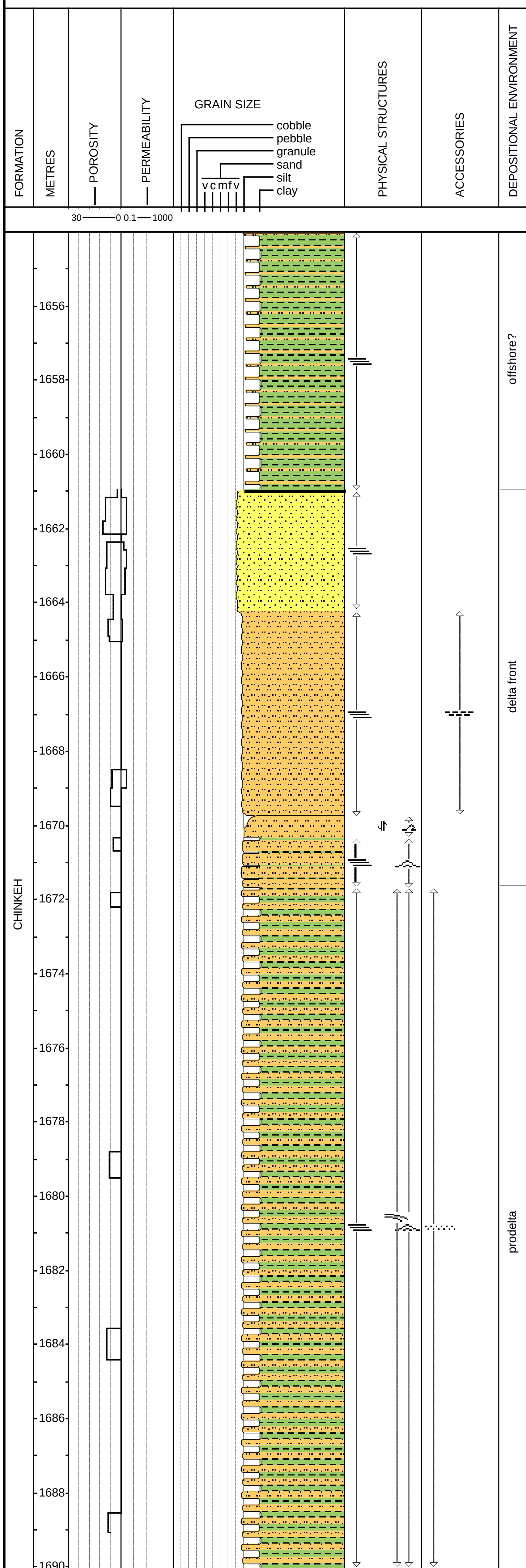
Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Marked b-97-A on core, but must be b-98-A.**

Core 2: 1672.2 - 1690.4

Core 1: 1654 - 1672.2

Most of core not slabbed.



REMARKS

1660.98 - 1654. Sharp basal contact. Predominantly dark grey shale above with interbedded siltstones.

1669.73 - 1660.98. Dominantly very finely laminated calcareous siltstone coarsening upard to very fine sandstone with minor shale interbeds. Planar laminations pervasive throughout, but increasingly difficult to see upwards because of lack of interlaminated fines, especially above 1664.2.

1670.34-1669.73. Grey siltstone with contorted bedding and possible slickensides.

1671.68 - 1670.34. Finely laminated to crosslaminated calcareous siltstone with minor shale interbeds. More massive toward top.

1690.4 - 1671.68. Interbedded, highly calcareous light grey sandy siltstone and dark grey shale. Siltstones massive to very finely laminated with bed thicknesses up to 1.3m but generally ~ 30 cm. Some minor cross-lamination (oscillatory) and possible hummocky cross-stratification. Minor silty very fine sandstone intervals. Shales very fissile, with minor fine siltstone laminations and cross-lamination.

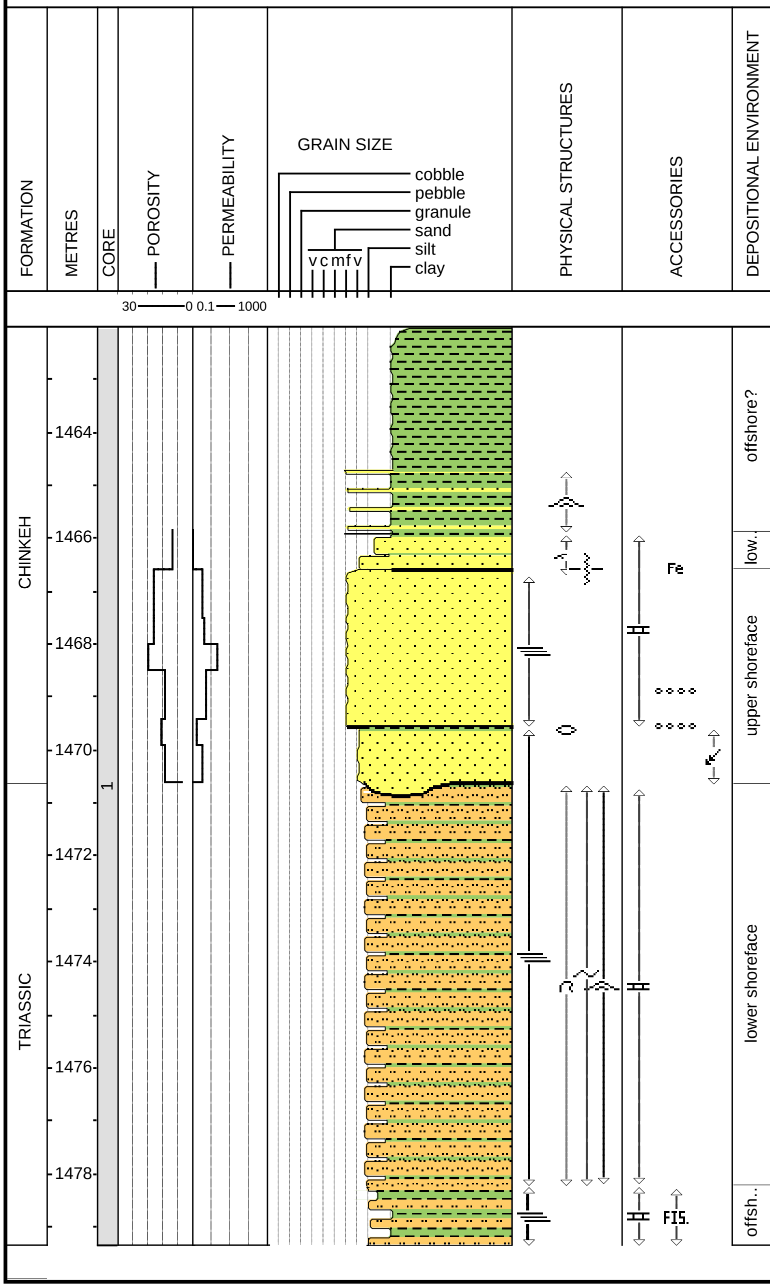
Can Hunter Maxhamish

02/b-71-K 94-O-6

Date Logged: June 24, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Cored interval: 1462–1480m, 17.36m recovered.**
Depths marked on cores may be ~2m too deep.
Core slabbed and clean.
Reported as gas zone but not tested.



REMARKS

1465.93-1462.00. Gradational contact to dark grey to black, dense mudstone. A few minor interbeds of cross-laminated sandstone near base.

1469.57-1465.93. Sharp basal contact overlain by chert granules up to 2 cm in size. Very finely laminated to nearly massive fine to very fine light grey sandstone, with minor coarse sand scattered throughout. Prominent pebble bed at 1468.85. Calcareous in places. Some crossbedding in upper m. 10 cm thick ironstained interval at 1466.6m overlain by 2 cm of black mudstone. Above this finely laminated very fine siltstone with cross-lamination and minor thin mudstone beds.

1470.65-1469.57. Basal contact prominently scoured. Very fine, finely planar-laminated sandstone above. Laminations horizontal to gently inclined. Minor carbonaceous partings. Grades at top into 4 cm of dark grey mudstone with lenses of siltstone.

1478.25-1470.65. Gradational contact into interbedded light grey siltstone and grey mudstone. Siltstones massive to oscillatory cross-laminated, some hummocky cross-stratification. Siltstones beds have sharp planar to loaded basal contacts. Mudstone intervals bioturbated. Calcareous in places.

1479.36 - 1478.25. Finely interlaminated dark grey shale and grey siltstone. Thin bedded to fissile. Slightly calcareous.

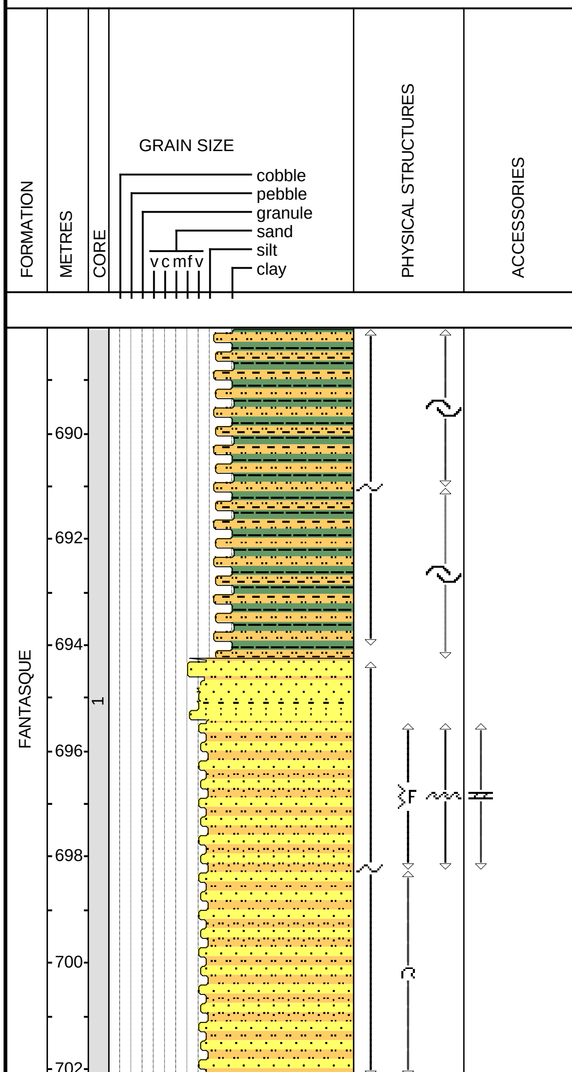
Aquitaine et al. Tattoo

A-27-L 94-O-10

Date Logged: June 25, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Core not slabbed and not logged in detail. No core analysis.**
Cored interval: 688 – 702.2m.
DST of 695–735 produced 729m water.



REMARKS

694.27 - 688.00 Contact not observed. Interbedded massive dark brownish grey mudstone and extremely fissile and friable black shale. Scattered bioclastic debris in the mudstone, especially near top.

695.43 - 694.27. Dominantly fine sandstone with sandy mudstone interbeds, becoming more common upward.

698.21 - 695.43. Fine sandstone and muddy, bioturbated very fine sandstone to sandy mudstone with contorted bedding. Pervasive fractures filled with dolomite.

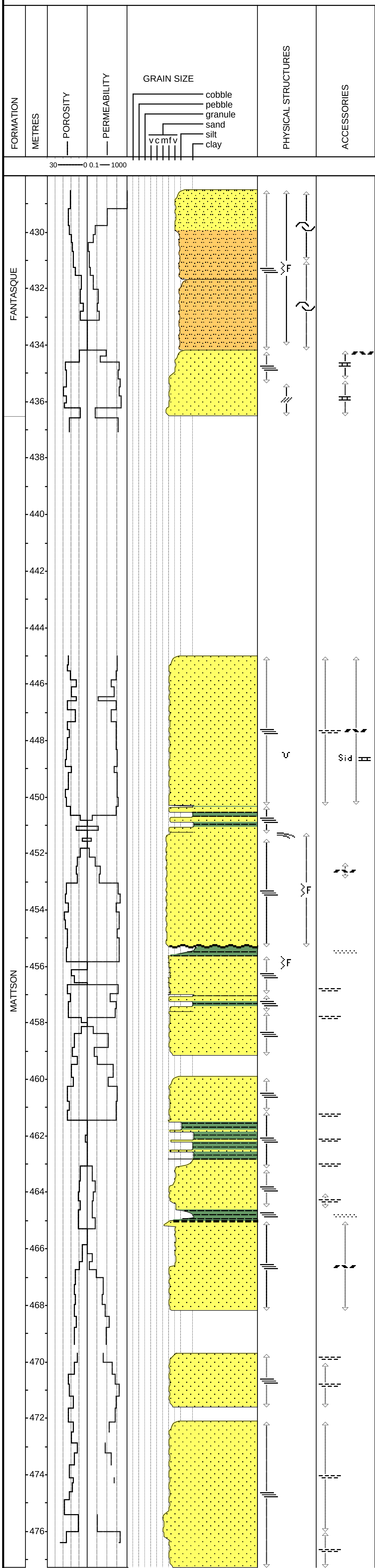
702.16 - 698.21. Interbedded fine sandstone and muddy, bioturbated very fine sandstone to sandy mudstone. Bedding highly inclined and often irregular.

Aquitaine Ammin et al Windflower
D-87-A 94-O-11

Date Logged: October 8, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Five cores taken from 428 – 477.3m, but less than 40m recovered, some core badly fragmented.**
Perf'd intervals: 434.7–474.9, 476.1–481.6
Produced 245.1 e6 m3 gas since 4/2002



REMARKS

434.19 - 428.50. Mottled greenish grey sandy mudstone coarsening upward to silty sanstone near top. Sand-sized bioclastic debris abundant. Vertical fracturing common. Bedding indistinct, sub-horizontal, defined by variations in color and bioclatic content.

436.51 - 434.19. Light tan sandstone, fine to medium at base, fining upward into very fine sand at top. Lower part has high-angle cross-stratification, upper part only faint horizontal lamination. Slightly to highly calcareous. Long vertical open pores from dissolution of calcite fracture fills in upper 20 cm. Minor green mud clasts in upper 20cm.

450.28 - 445.00. Light grey, fine sandstone with crude horizontal bedding largely defined by minor green shale laminae. Prominent mineralized zone with white calcareous concretions with brown (siderite?) rims.

451.25 - 450.28. Interbedded light grey fine sandstone and green shale.

455.33 - 451.25. Light grey, fine to medium sandstone. Basal contact sharp with prominent loading. Faint planar, near-horizontal laminations throughout defined by slight changes in grain size. Rare cm-scale graded bedding. A few horizons with accumulations of coarse sand to granule size brown mud clasts. Upper part fines upward to very fine, wavy bedded to hummocky? stratified sandstone at top.

455.63 - 455.33. Green shale with finely interlaminated sandstone near base and top, near planar horizontal bedding.

459.14 - 455.33. Dominantly light grey fine sandstone. Core very rubbled--two prominent shale interbeds are of uncertain thickness, possibly in the range of 457.6-457m. Near these interbeds green shaly partings define cm-scale bedding, elsewhere sandstone largely massive. Prominent diagonal open fracture in upper part.

461.48 - 459.90. 10cm of very finely interlaminated sandstone and green shale grading upward into light grey, massive fine sandstone.

462.83 - 461.48. Light green shale with minor fine sand beds up to 20cm thick. Gradational contacts at top and base.

464.58 - 462.83. Light grey fine to very fine sandstone. Finer and slightly greenish in lower 22cm and upper 89 cm. Green shaly partings abundant at top and base, otherwise largely massive.

465.01 - 464.58. Light green, very fissile shale. Fine planar laminations throughout. Minor fine sandstone laminae. Basal contact not observed.

468.17 - 465.01. Light grey fine to very fine sandstone with minor green shaly partings throughout defining sub-horizontal bedding surfaces a few cm apart. Fines upward until 12cm from top where there is a medium sand lamina; fines to fine sand above that. Minor biomoldic porosity especially near top. Parts of core very rubbled, possibly jumbled.

469.84-469.7. Light grey fine to very fine sandstone, slightly more tan in color than below. Abundant greenish clay partings.

472.1? to 469.84. Light grey fine sandstone, largely massive. Subhorizontal bedding defined by rare carbonaceous partings, otherwise very uniform, well-sorted.

~ 476.38 - 472.10. Light grey, fine to medium-grained sandstone with minor carbonaceous partings. Coarsest around 464. Crudely stratified with planar bedding surfaces ~5-10 cm apart. Moderately porous.

Ammin Aquit Windflower

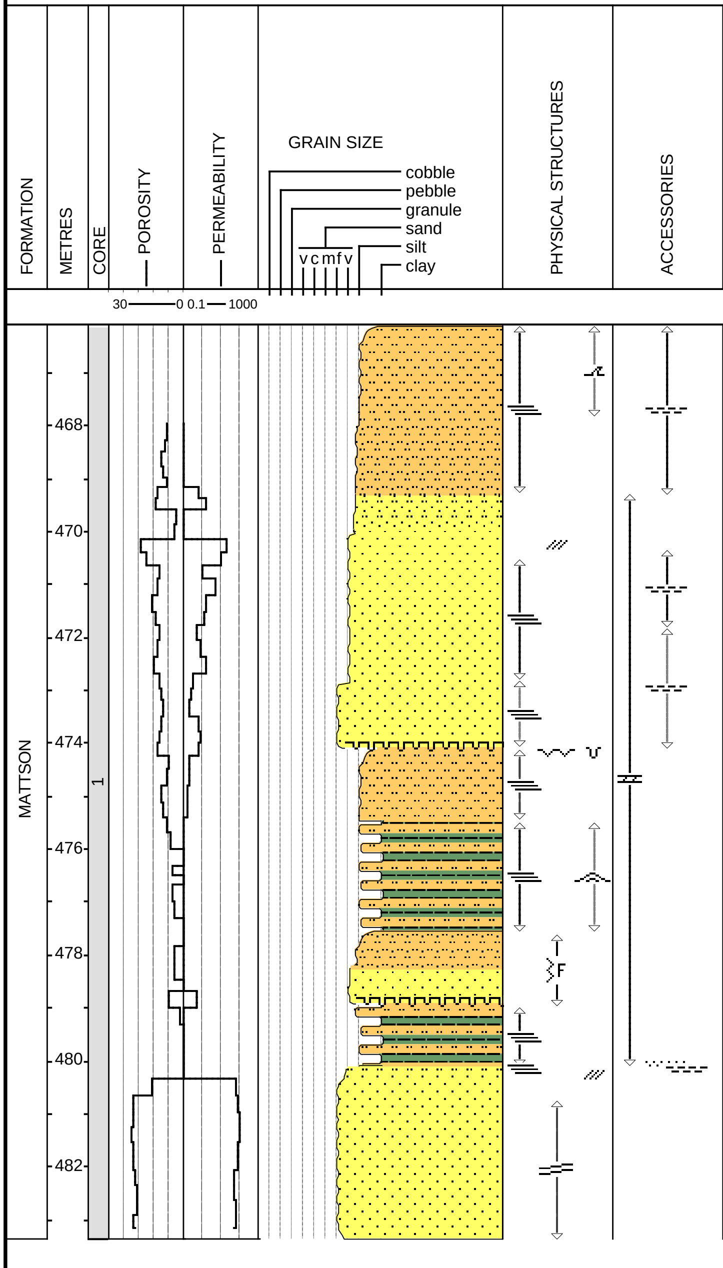
D-67-A 94-O-11

Date Logged: June 25, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Cored Interval: 466.1 – 483.4.**

DST: Avg. perm indicated, flowed water, gas cut mud



REMARKS

469.32 - 465.1. Gradational contact to grey, sandy wiltstone with abundant shaly partings, grading upward into finely laminated light and dark grey siltstone with minor fine-scale loading structures.

474.11 - 469.32. Sharp, irregular contact--possible hardground. Dolomitic white fine sandstone grading upward into light grey very fine dolomitic sandstone. Lowermost 1m is massive except where bedding surfaces defined by rare irregular clay laminae; fine horizontal to inclined planar laminations more common farther up. Prominent 2cm shale bed at 470.5m, overlain by crossbedded very fine sands, fining upward into massive sandy dolomitic siltstone.

475.50-474.11. Grey, dolomitic sandy siltstone to sandy dolomite. Discontinuous, irregular dark clay laminae scattered throughout. Possible mudcracks near top and a vertical burrow.

477.56 - 475.50. Interbedded grey shale and light grey dolomitic siltstone. Shales very soft and friable, siltstones have fine discontinuous clay laminae and minor ripple lamination.

478.98 - 477.56. White dolomitic very fine sandstone grading upward into light grey dolomitic sandy siltstone. Base highly irregular, possible hardground. Abundant dolomite-filled vertical fractures. Massive near base, becomes more mottled in appearance upwards.

480.10 - 478.98. Interbedded dark grey shale and grey siltstone (to dolomite?). Gradational base with minor sandstone beds and laminae in lowermost 10 cm.

?? to 480.1m. Light grey sandstone, rather poorly consolidated and rubbled, especially toward base. Becomes more tightly cemented near top. Crude low-angle planar bedding common in lower part, crossbed around 480.25m. Uppermost 10cm becomes increasingly muddy upwards with both more matrix clay and minor clay laminae.

AEC Maxhamish

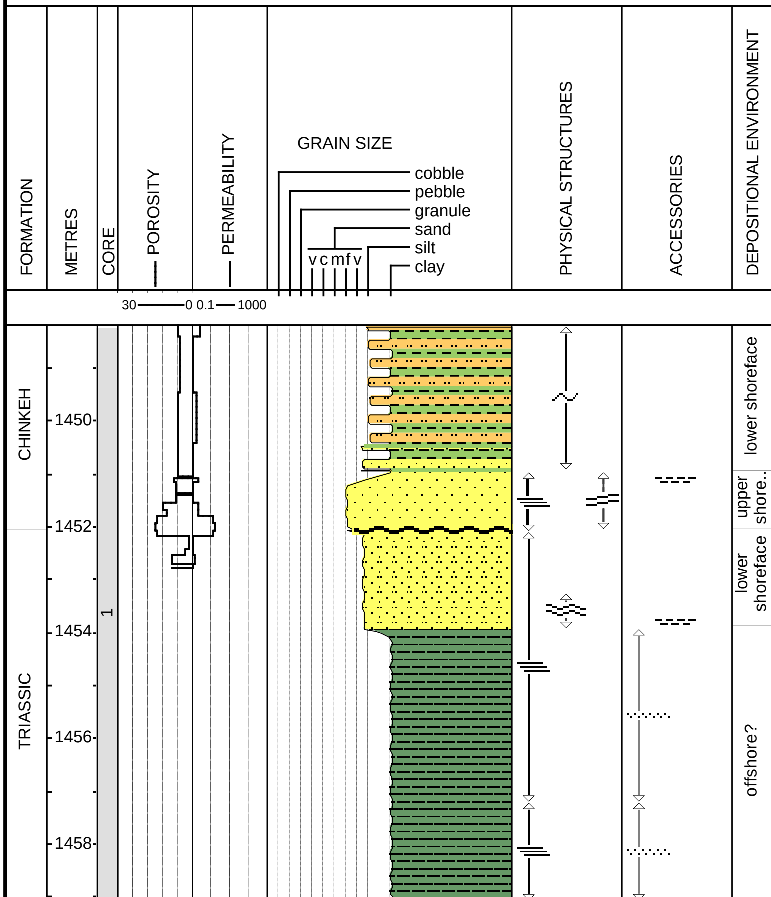
A-13-G 94-O-11

Date Logged: June 25, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Cored interval: 1448.2 – 1466.2m**

Tested gas from 1453.6–1453.9, but not produced.



REMARKS

1450.95 - 1448.20. Gradational contact. Dark grey bioturbated mudstone finely interbedded with grey siltstone to very fine sandstone; no sandstone above 1450.5m.

1452.09 - 1450.95. Sharp basal contact appears scoured. Very finely laminated light and dark grey fine sandstone, fining upwards to very fine sandstone at top. Planar horizontal to low angle laminations pervasive. Minor black shale laminae in upper 35cm.

1453.4 - 1452.09. Gradational basal contact with siltstone to very fine sandstone. Siltstone laminae increase in thickness over lowermost 20cm; no shale above that point. Laminations in lower part planar to wavy with minor coarse sand-sized ripups. Fine, but faint horizontal planar laminations above that.

1459.1 - 1453.4. Black shale, very fissile and friable with rare sandstone laminae. One pair of very fine sandstone beds totalling 15 cm in thickness with a minor shale and rip-up clasts separating them in upper part of section.

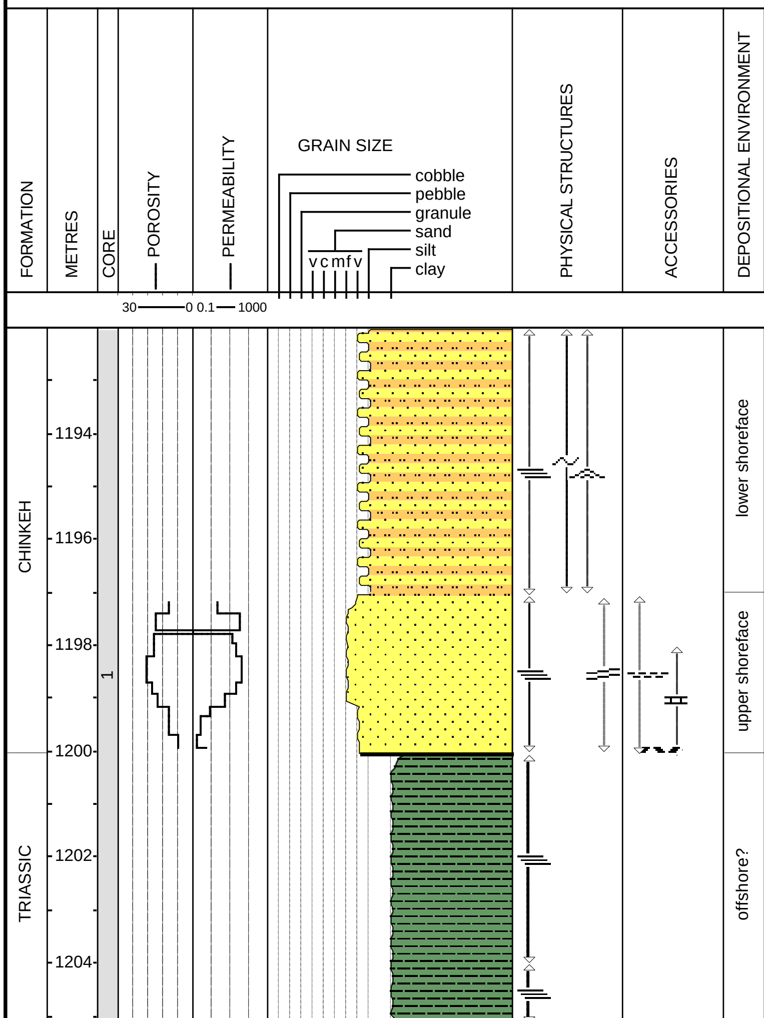
AEC Maxhamish

C-18-A 94-O-14

Date Logged: June 25, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Cored Interval 1192-1205m.**
Upper 4.5m not slabbed and very dity.
Perfed from 1197-1199, produced 18.7 e6 m3 gas since 2/2001



REMARKS

1997.04 - 1992.00. Interbedded bioturbated dark grey mudstone and finely laminated light grey fine to very fine silty sndstone. Bioturbation pervasive but very low diversity. Wave ripples common in sandstone units. Description based on lower slabbed part--upper part appears similar but very dirty.

1200.04 - 1997.04. Sharp basal contact with layer of granule-sized mud clasts at base. Very fine to fine sandstone, very finely laminated throughout. Laminations of light and dark grey sandstone, planar and horizontal to low-angle inclined. A few minor black shale interbeds up to 10 cm in thickness, with the two thickest ones in the upper meter of section, although overall sections coarsens upward slightly. Slightly calcareous in lower part.

1205.15 - 1200.04. Interbedded red and black shale. Thin bedded, moderately fissile.

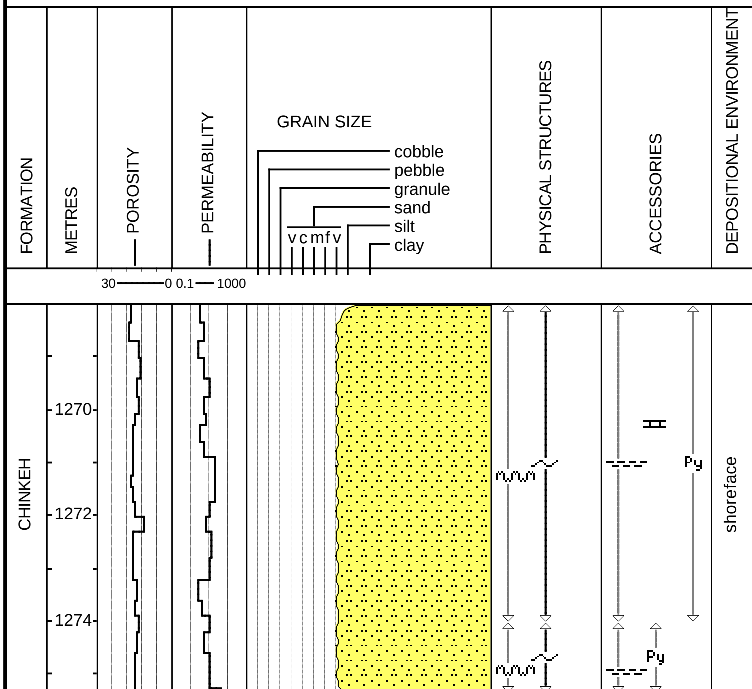
AEC Maxhamish

A-50-I 94-O-14

Date Logged: June 25, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Core #2: Interval: 1268–1286 m (7.37m recovered)**
(depths according to boxes – probably > 1272m judging by logs)
Core slabbed and clean
Reported as gas zone but no tests



1268-1275.37. Gray, mottled silty very fine sandstone. Bioturbated with lined vertical burrows and some round horizontal traces (planolites?). Minor shaly partings and pseudostylolites define bedding in otherwise rather massive section. Dominantly quartzose/chert sand. Minor pyrite. Moderate porosity throughout, slightly lower from 1269-1270 where occluded by calcite.

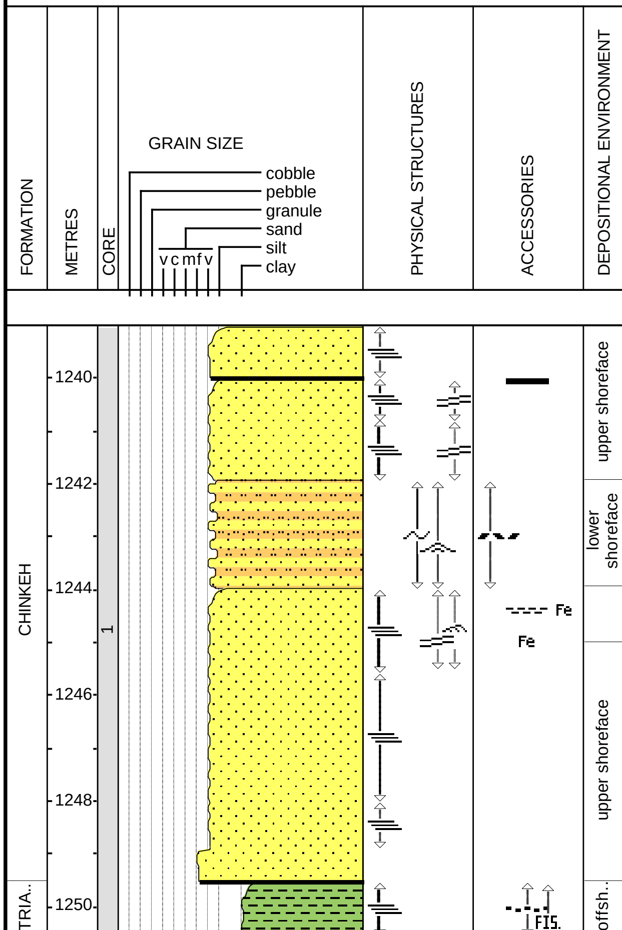
AEC Maxhamish

A-50-I 94-O-14

Date Logged: June 25, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Core #1: Interval: 1239–1257 (11.54 m recovered)**
Core slabbed and clean
No core analysis



REMARKS

1240.00 - 1239.00. Very fine sandstone, more massive in apearance than below.

1241.93 - 1240.00 Very fine sandstone with pervasive horizontal planar laminations made apparent by heavy minerals (?). 1 cm thick coal seam at top.

1243.97-1241.93. Interbedded very fine sandstone and bioturbated sandy mudstone. Sandy intervals planar laminated to oscillatory cross-laminated, possible hummocky. Siltstone intervals bioturbated, predominantly by feeding traces with spreite. Carbonaceous fragments common in sands.

1245.50 - 1243.97. Dominantly very fine, very finely planar laminated sandstone. Minor inclined planar laminations and crosslaminations. Iron staining from 1244.89-1245m and around 1244.5, just below a shale lamina at 1244.37. Prominent escape trace just below 1244.5. Less porous than underlying sands.

1248.83-1245.50. Massive sandstone grades upward into very finely planar laminated, fine to very fine sandstone. Laminations highlighted by dark colored (prob. heavy minerals could be carbonaceous debris) laminae that become increasingly common upwards.

1249.52-1248.83 Sharp basal contact. Massive, light grey fine sandstone. Well-sorted, quartzose.

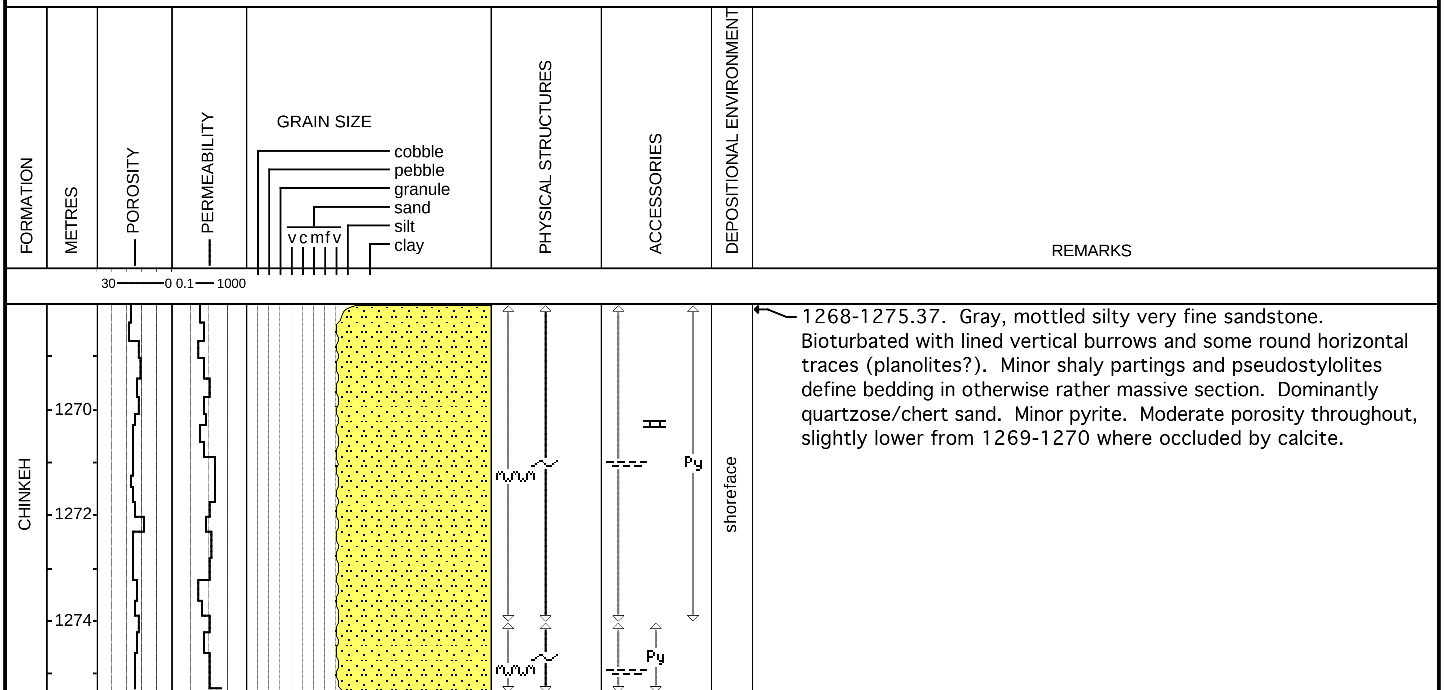
1250.54 - 1249.52. Dark grey, slightly carbonaceous fissile shale interbedded with thin bedded dark grey mudstone.

AEC Maxhamish
A-50-I 94-O-14

Date Logged: June 25, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Core #2: Interval: 1268-1286 m (7.37m recovered)**
(depths according to boxes - probably > 1272m judging by logs)
Core slabbed and clean
Reported as gas zone but no tests



1268-1275.37. Gray, mottled silty very fine sandstone. Bioturbated with lined vertical burrows and some round horizontal traces (planolites?). Minor shaly partings and pseudostylolites define bedding in otherwise rather massive section. Dominantly quartzose/chert sand. Minor pyrite. Moderate porosity throughout, slightly lower from 1269-1270 where occluded by calcite.

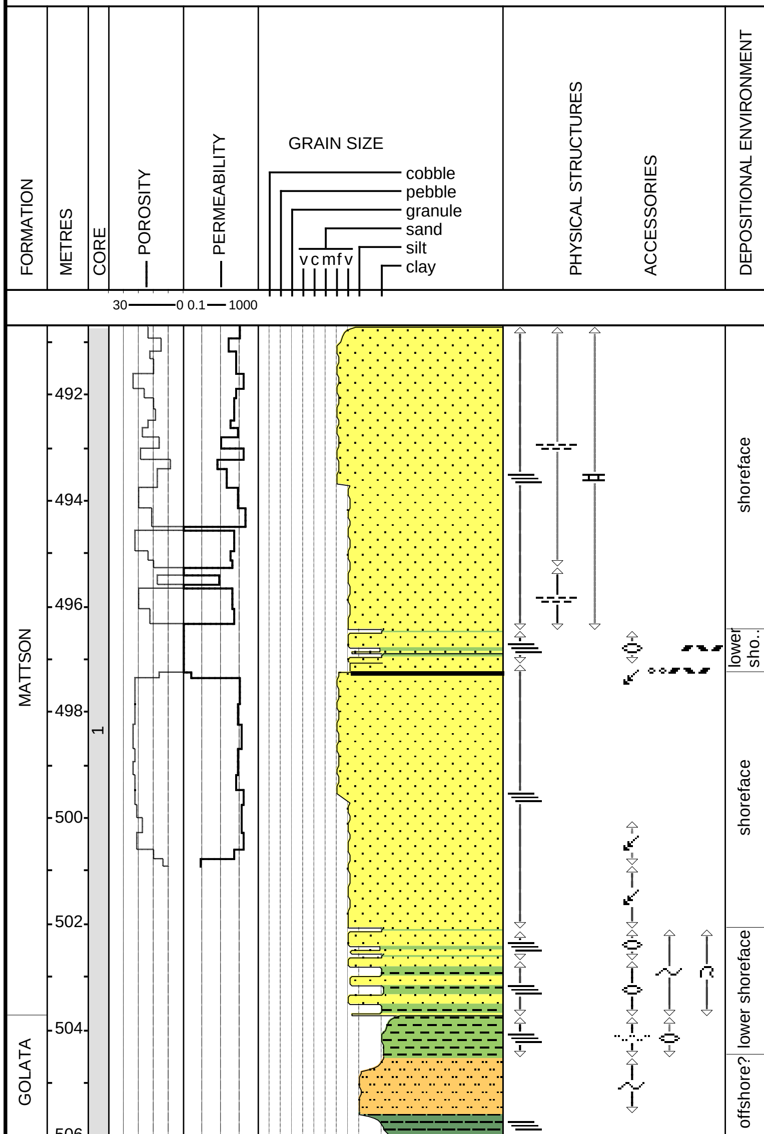
Aquitaine Tattoo

A-2-D 94-O-15

Date Logged: June 25, 2009

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: **Cored Interval: 490.7–506.6, about 15.3 m recovered.**
DST recovered water, gas to small to measure. Average perm indicated.
Core slabbed and clean.



REMARKS

496.46-490.7. Light tan, very fine to fine sandstone. Calcareous n places. Porosity moderate to good. Shaly partings abundant in lower part, decreasing upwards; rare baove 495.24m.

497.11-496.46. Interlaminated to lenticular bedded light grey very fine sandstone and black to dark reddish brown mudstone. Becomes sandier upwards. Sideritized mudclasts at the sharp base of one 10 cm thick sandstone bed.

502.11 - 497.11. Light tan, very fine to fine sandstone, coarsens upwards slightly. Carbonaceous/shaly partings abundant in lower part, decreasing upwards, rare above 500.05m. Fine horizontal planar laminations in places, elsewhere more massive in appearance. Well-sorted, quartzose sand with minor lithic fragments and pyrite. Upper 18 cm has a sharp bed with minor chert granules and sideritized mud clasts.

503.75 - 502.11. Finely interlaminated to lenticular bedded very fine light grey sandstone and dark grey mudstone. Loading structures common. Minor bioturbation, some planolites. Becomes increasingly sandy upwards. Dominantly sand above 502.6m.

504.53-503.75. Laminated dark grey mudstone with minor siltstone lenses and laminae. Some planolites burrows.

505.59-504.53. Gradational basal contact. Mottled, light and dark grey, bioturbated siltstone.

506.02 - 505.59. Very fissile, laminated black shale.

MATTSON
APPLECORES

Aquitaine et al Kiwigana

C-37-G 94-O-6

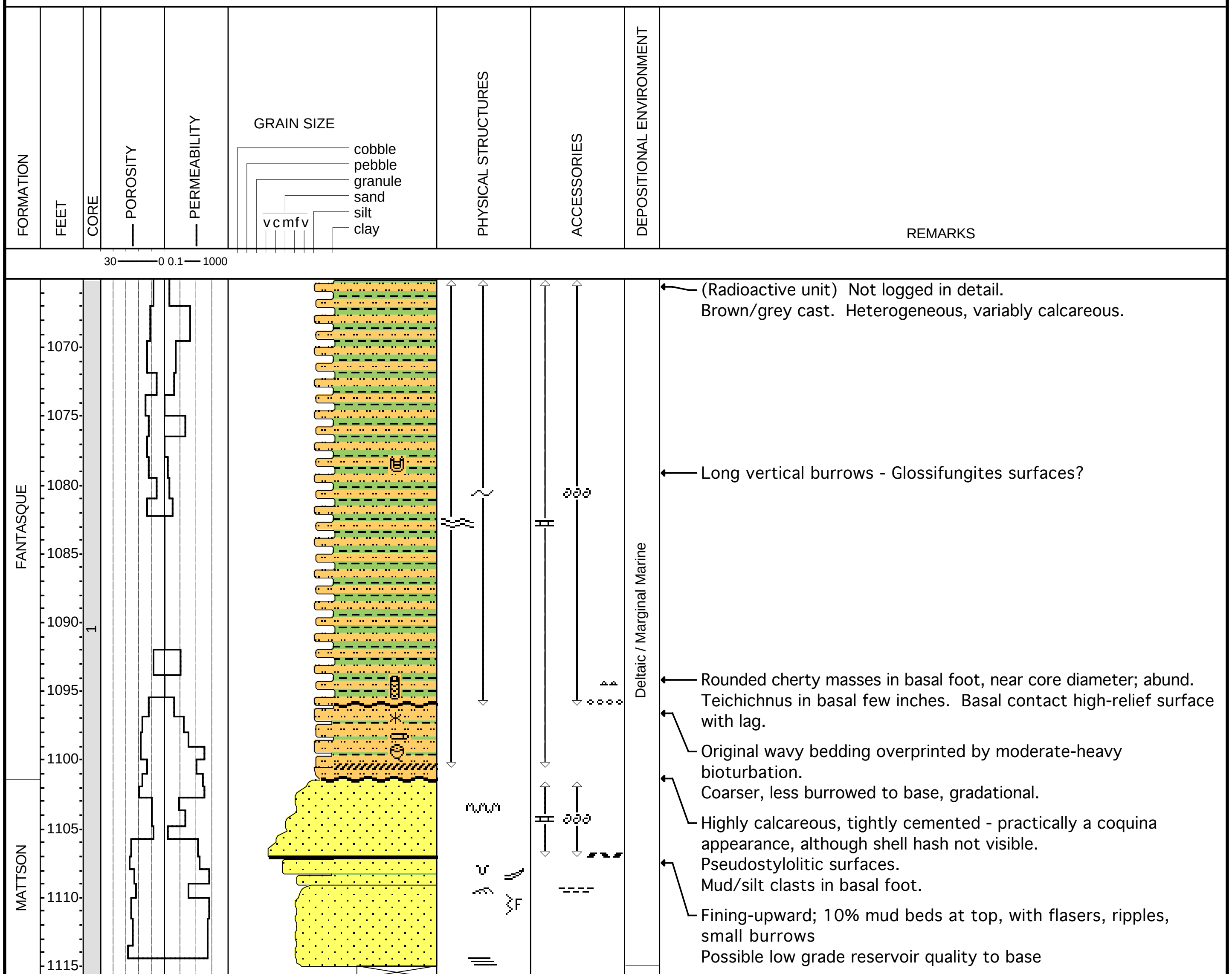
Date Logged: May 31, 2000

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1065-1116' (Rec. 50')

4" core, slabbed, clean, core analysis done

Sand supply very fine, with admixture of abundant calcareous material.
Repeated high energy events probably incorporated a lot of shell material into fining-upward sequences.



Aquitaine et al Tattoo

A-78-L 94-O-10

Date Logged: May 31, 2000

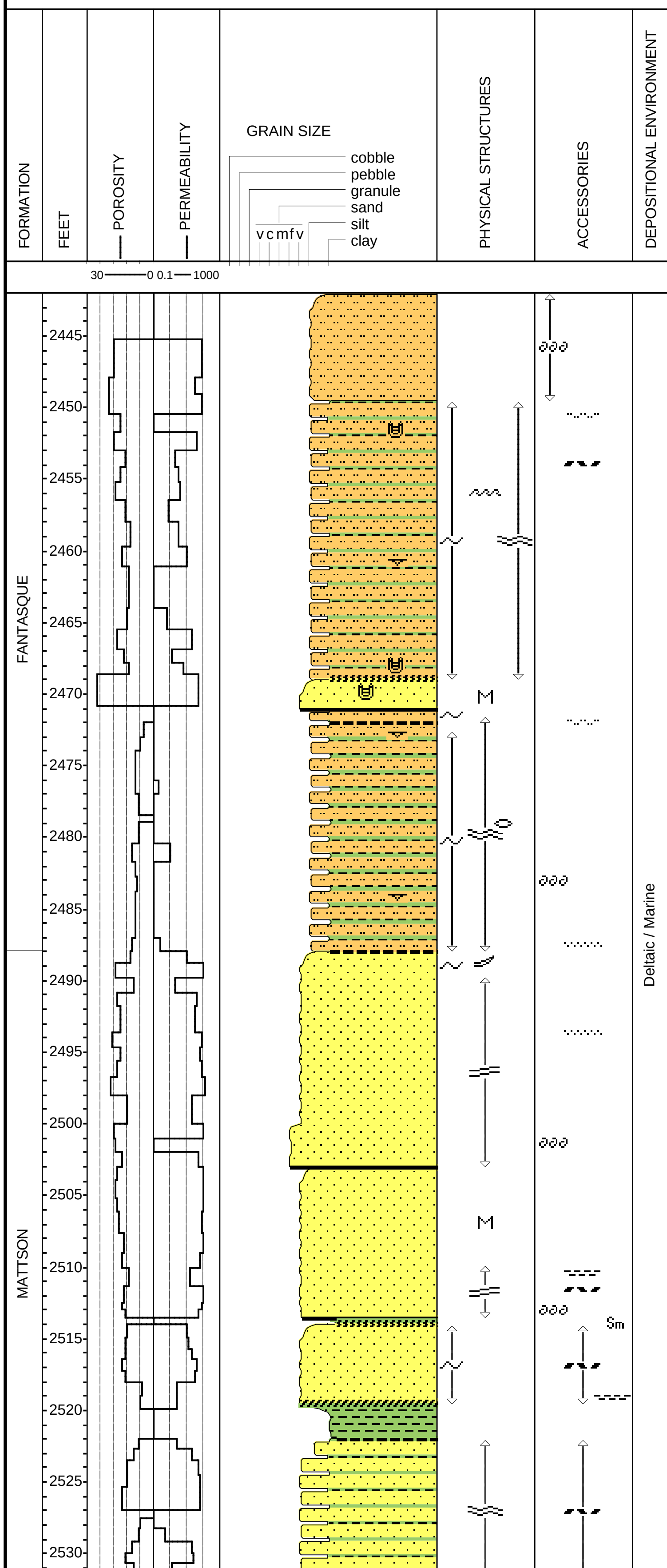
Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 2442-2472' (Rec. 30')

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

3.5" core, slabbed

Deltaic / shoreface sandstones, episodically transgressed. Probable Glossifungites surfaces.



REMARKS

Irregular deformed dolomitic/coquinoid siltstone masses.
Abundant robust dolomitized shell fragments.
Isolated moldic porosity (shell solution).

Finely laminated, wavy/heterolithic, overprinted by pervasive burrowing; Diplocraterion at top and base
Irregularly distributed robust brachiopod shells
Discrete loaded/deformed beds, light grey, brecciated and fractured - prelithified?

Low porosity/permeability.
One long vertical trace, likely Diplocraterion.
Complete brachiopod shell on broken surface.

Grey, variable small scale burrowing

Wavy /lenticular bedding overprinted by pervasive burrowing - mostly small scale, some larger vertical burrows
Abundant robust brachiopods, many intact.
Tan and grey cast, poor permeability/porosity, not calcareous.
Abundant coarse-v coarse sand grains (some chert?) in basal foot

Very fine, with small % chert-rich coarser grains in laminae highlighting cross-bedding. Upper foot sl. argillaceous, burrowed
Basal 3' coarser, some moldic leached porosity (shell fragments)
Some moderate reservoir quality

Massive to vaguely low-angle planar laminated; bedding better displayed to base where there is more lithic contrast
- lower 5' - few green shale partings, thin flat green mud clasts, minor shell debris

Dark apple green shade, smectitic.

More heterogeneous - burrowed aspect. Thin flat green mud clasts appear to have been partially "digested" in rock framework.
Gradational base, 6" heterolithic.

More heterolithic, with green shale beds and heterolithic clasts to core diameter. Poorer reservoir - not as clean, more cemented aspect; minor coarser sand grains.

AmMin Aquitaine et al Windflower
D-6-H 94-O-11

Date Logged: June 1, 2000

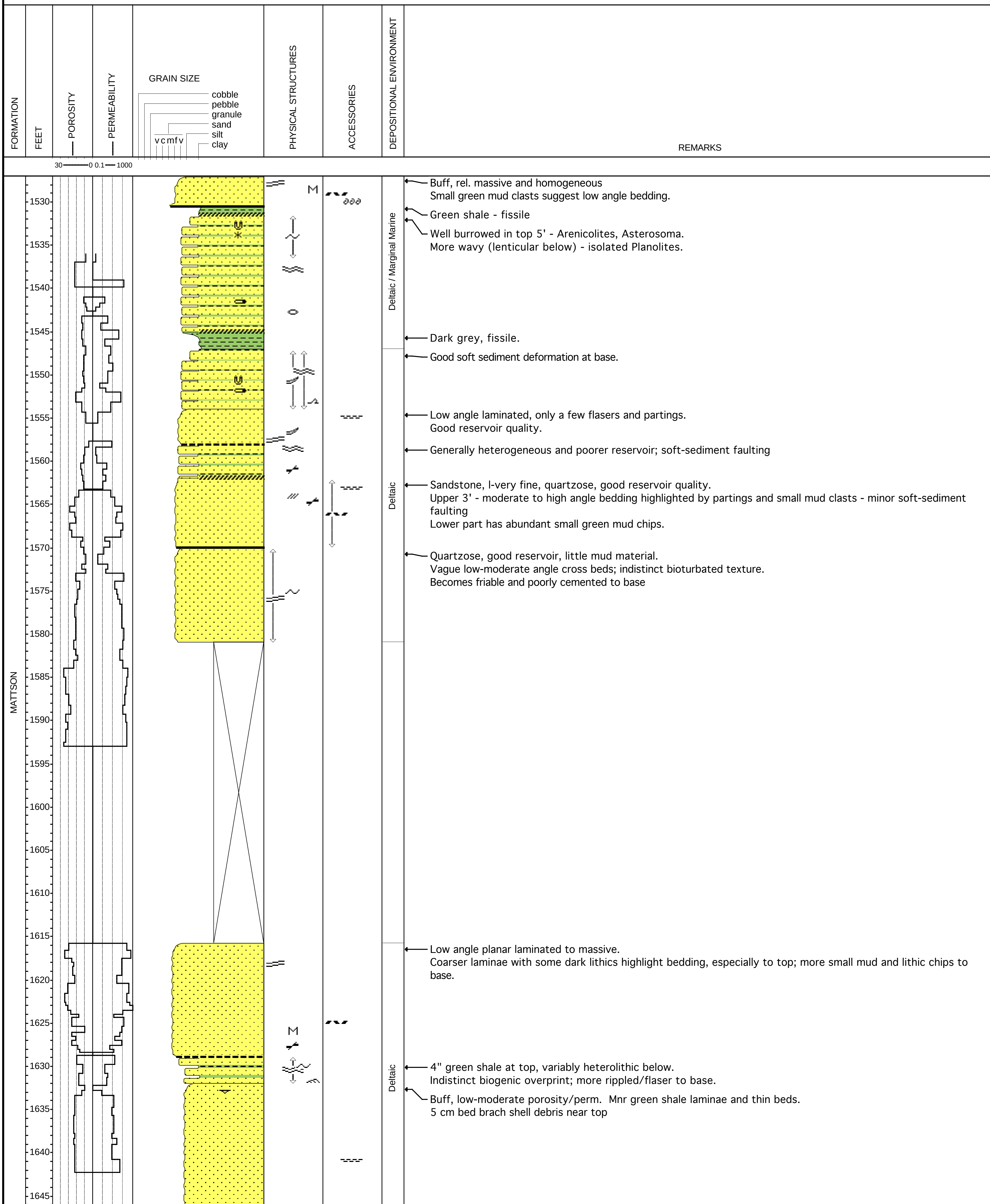
Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #2: 1526.9-1586 (Rec. 56')

Core #3: 1616-1647 (Rec. 31')

3.5" core, slabbed.

Core 3: Core analysis assumes core loss from top, based on friable sandstone in core 2, porosity interval in logs, and occurrence of tighter rock ~10' below top of recovered interval.



AmMin Aquitaine et al Windflower

D-6-H 94-O-11

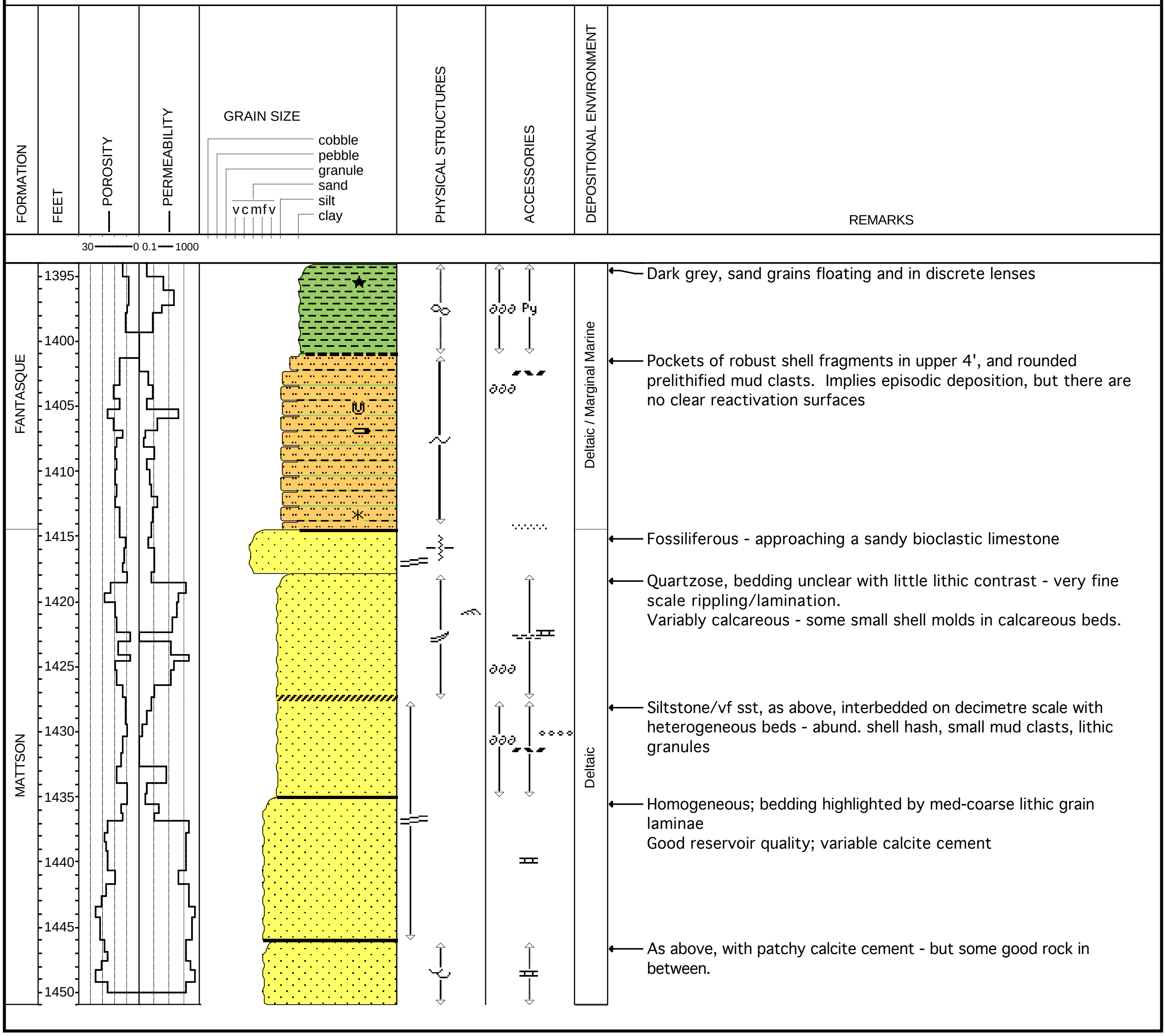
Date Logged: June 1, 2000

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #1: 1394-1454' (Rec. 56')

3.5" core, slabbed

Clearly a competition between marine influx and clastic supply - more terrestrial than other sections, with little open marine material and abundant cross-bedded sandstone - some relatively coarse and clean.



Imperial Pan Am Viscount

A-77-D 94-O-11

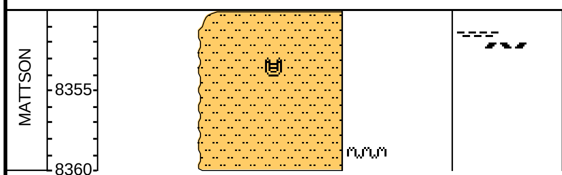
Date Logged: May 31, 2000

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #13: 8350-8360' (Rec. 10')

Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments. Siltstones show no evidence of reservoir quality.

FORMATION | FEET | GRAIN SIZE: cobble, pebble, granule, sand (v c m f v), silt, clay | PHYSICAL STRUCTURES | ACCESSORIES | REMARKS



Somewhat heterogeneous, but all very tight.

Shale partings and deformed sideritic mud clasts in upper 5'; moderate-low density large lined burrows - look like Diplocraterion from core ends, although unusually sinuous on slabbed faces.

More laminated, less burrowed to base - few stylolites.

Imperial Pan Am Viscount

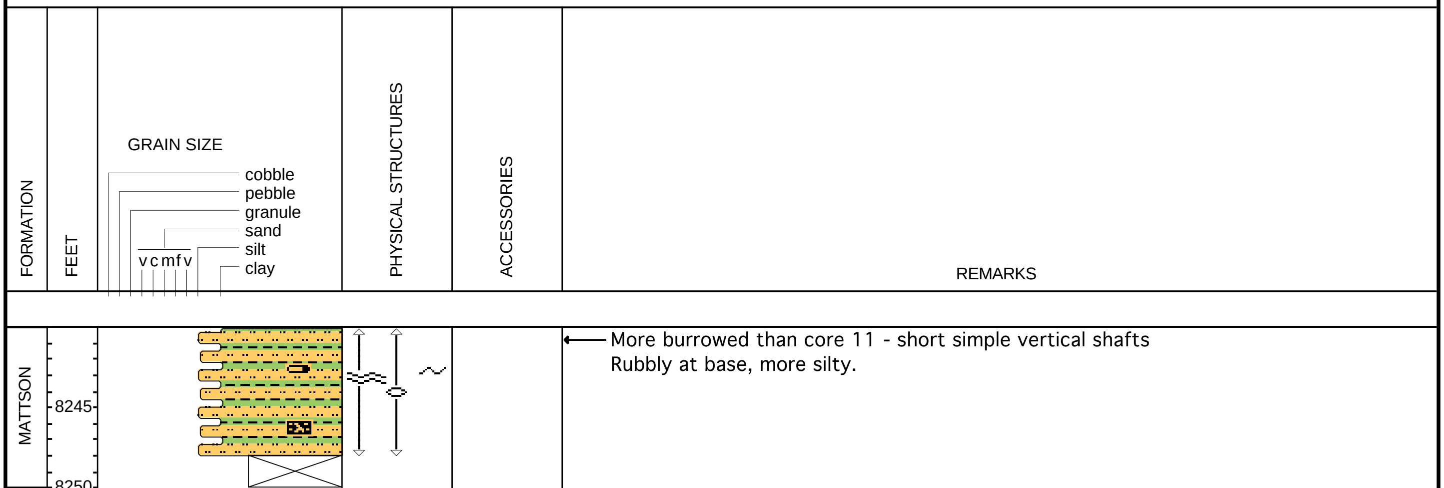
A-77-D 94-O-11

Date Logged: May 31, 2000

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #12: 8240-8290' (Rec. 8')

Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments. Siltstones show no evidence of reservoir quality.



Imperial Pan Am Viscount

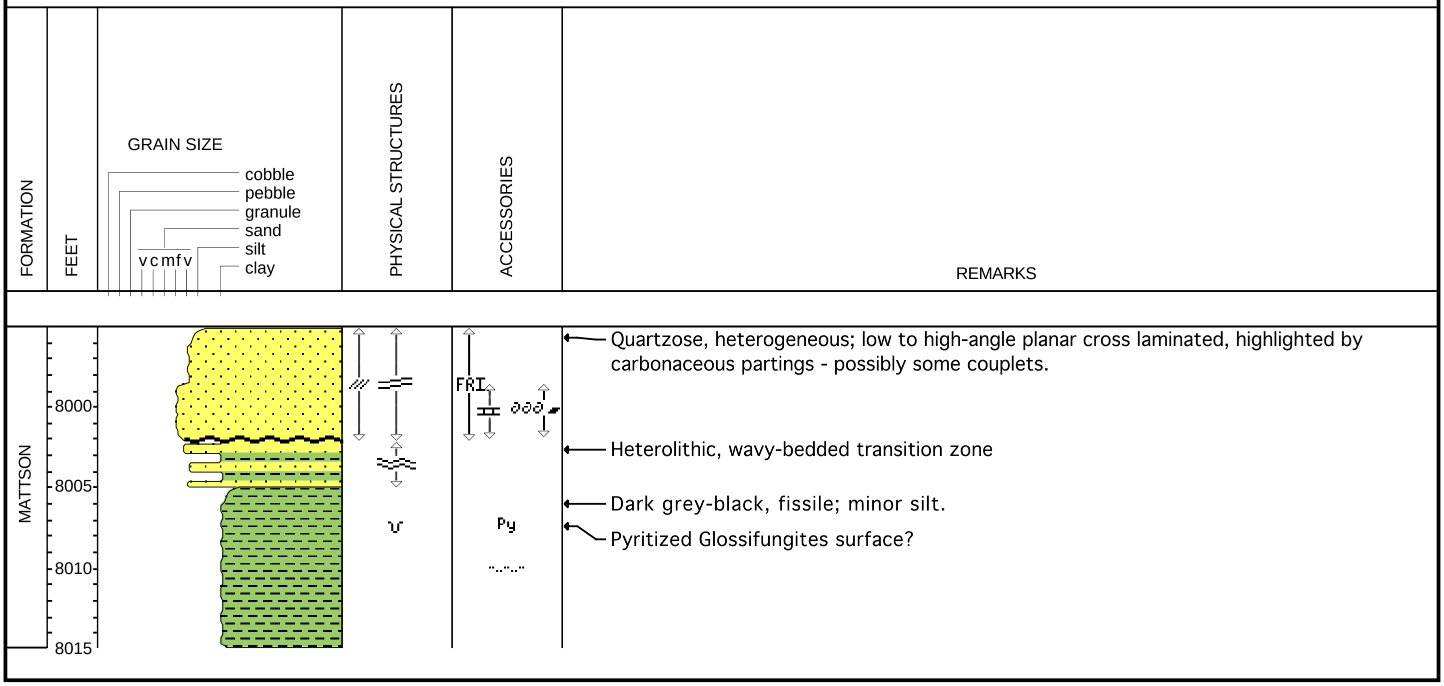
A-77-D 94-O-11

Date Logged: May 31, 2000

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #9: 7995-8015' (Rec. 19')

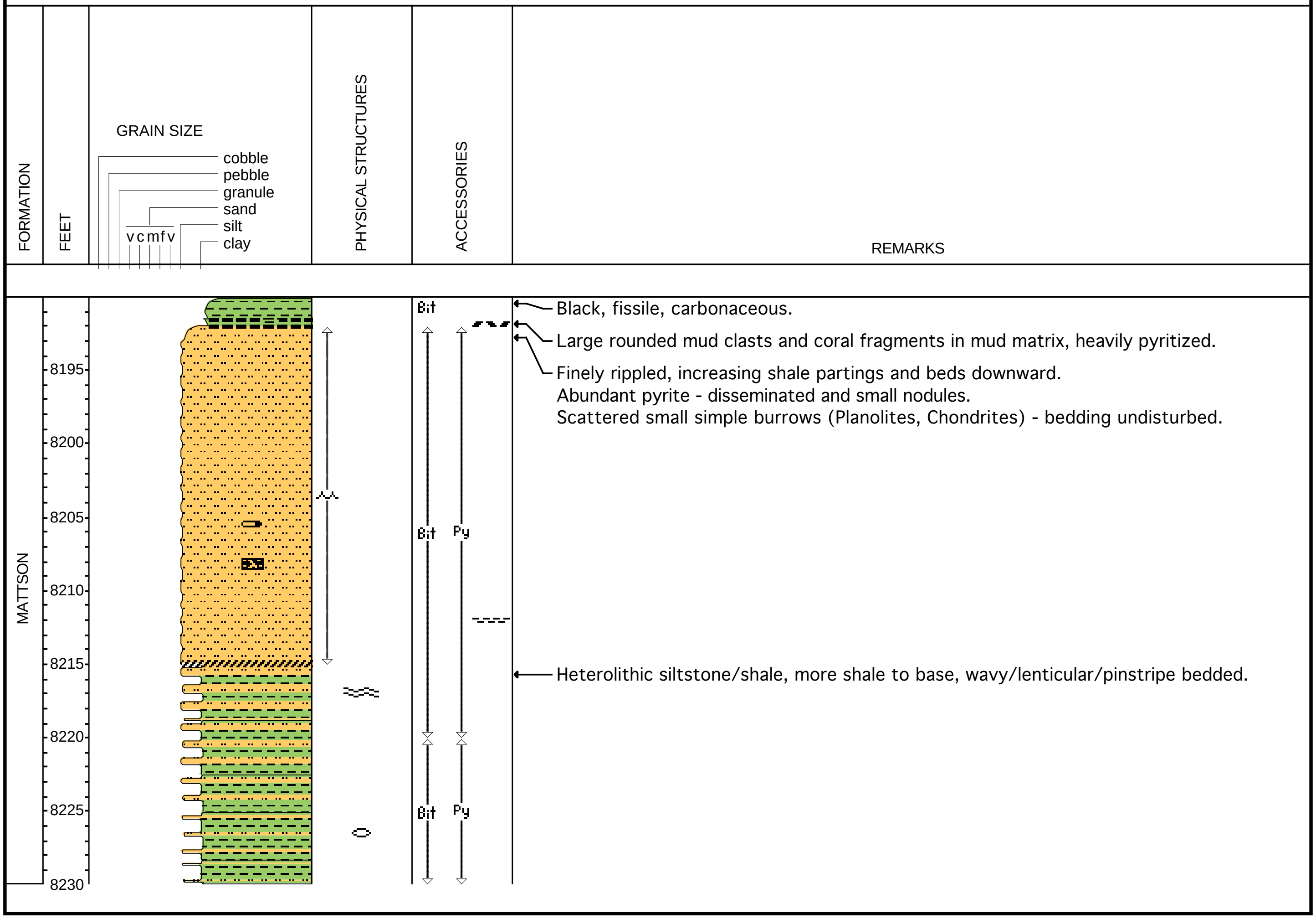
Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments. Siltstones show no evidence of reservoir quality.



Imperial Pan Am Viscount
A-77-D 94-O-11

Date Logged: May 31, 2000
Logged by: PETREL ROBERTSON CONSULTING LTD.
Remarks: Core #11: 8190-8230' (Rec. 40')

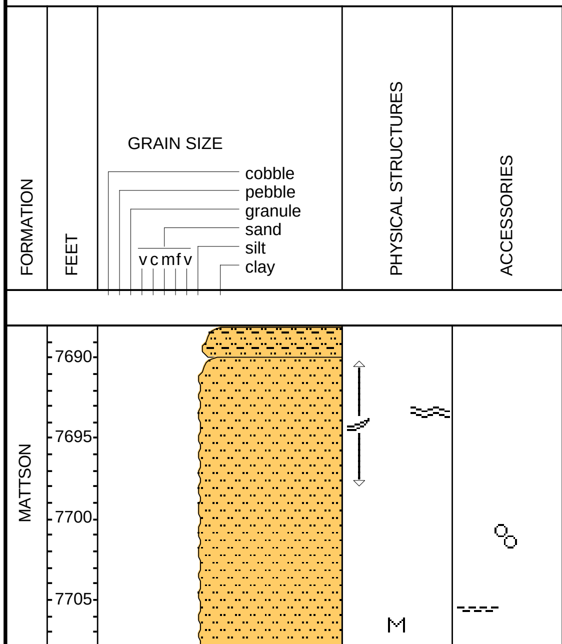
Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments.
Siltstones show no evidence of reservoir quality.



Imperial Pan Am Viscount
A-77-D 94-O-11

Date Logged: May 31, 2000
Logged by: PETREL ROBERTSON CONSULTING LTD.
Remarks: Core #8: 7688-7708' (Rec. 19.5')

Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments. Siltstones show no evidence of reservoir quality.



REMARKS

Near white, tight and quartzitic, no calcite.
Top 2' argillaceous, next 8' abundant flasers and thin wavy beds, next 4' diagenetically mottled (bitumen?)
Basal part massive - minor shale partings.

Imperial Pan Am Viscount

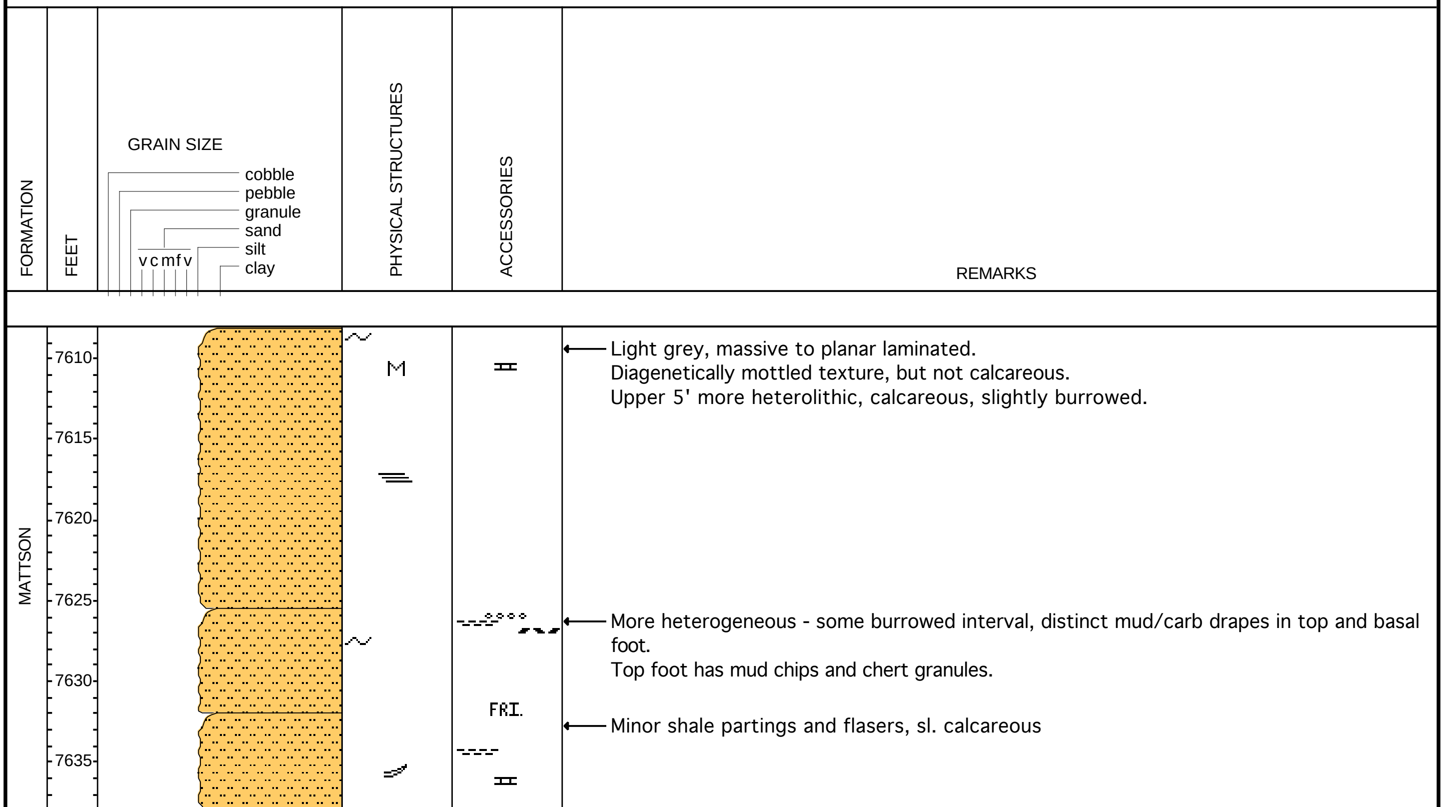
A-77-D 94-O-11

Date Logged: May 31, 2000

Logged by: PETREL ROBERTSON CONSULTING LTD.

Remarks: Core #7: 7608-7638' (Rec. 30')

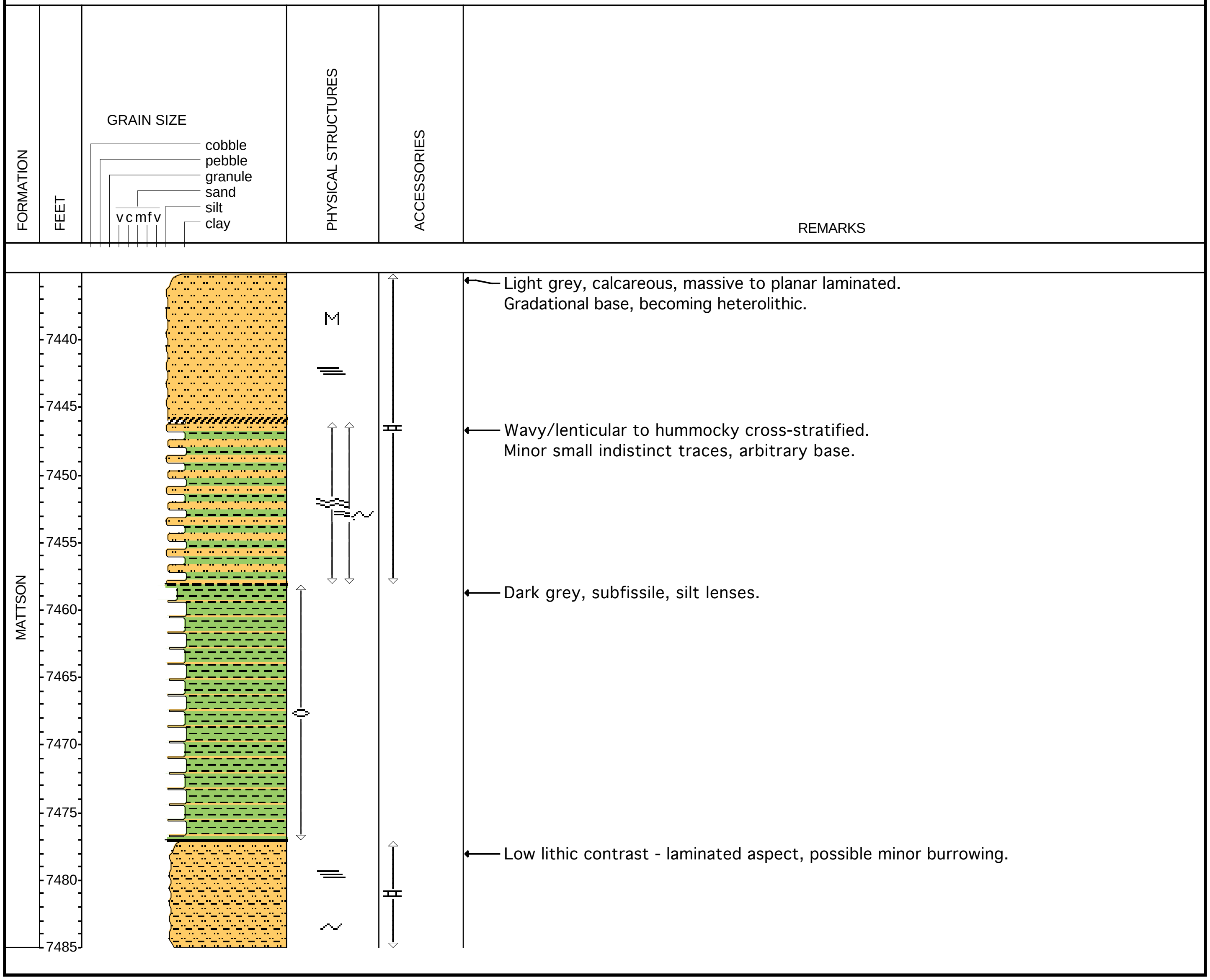
Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments. Siltstones show no evidence of reservoir quality.



Imperial Pan Am Viscount
A-77-D 94-O-11

Date Logged: May 31, 2000
Logged by: PETREL ROBERTSON CONSULTING LTD.
Remarks: Core #6: 7435-7485' (Rec. 50')

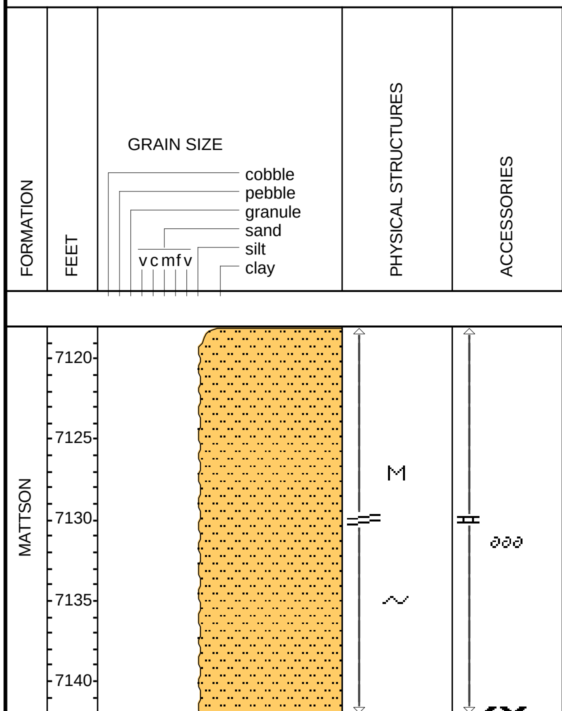
Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments. Siltstones show no evidence of reservoir quality.



Imperial Pan Am Viscount
A-77-D 94-O-11

Date Logged: May 31, 2000
Logged by: PETREL ROBERTSON CONSULTING LTD.
Remarks: Core #5: 7118-7142' (Rec. 24')

Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments. Siltstones show no evidence of reservoir quality.



REMARKS

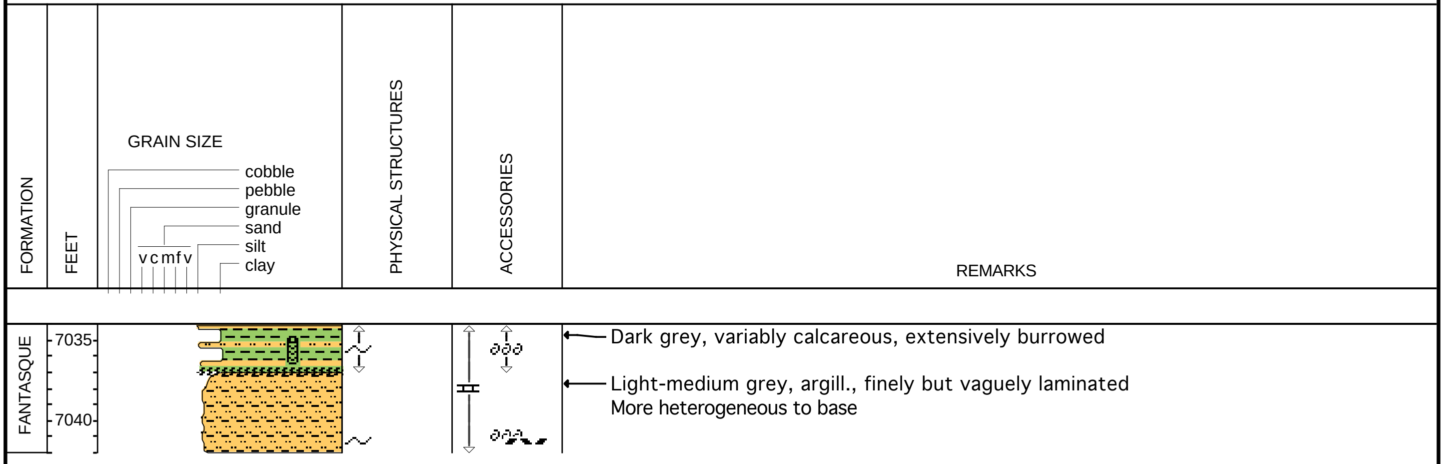
Greenish cast, slightly-very calcareous.
Low angle laminated aspect; minor massive intervals; some slightly heterolithic and burrowed.
Several coquinoid intervals

Imperial Pan Am Viscount

A-77-D 94-O-11

Date Logged: May 31, 2000
Logged by: PETREL ROBERTSON CONSULTING LTD.
Remarks: Core #4: 7034-7042' (Rec. 8')

Very carbonaceous nature and relatively scanty burrowing highlights distal deltaic/anaerobic environments. Siltstones show no evidence of reservoir quality.



ARCO Maxhamish

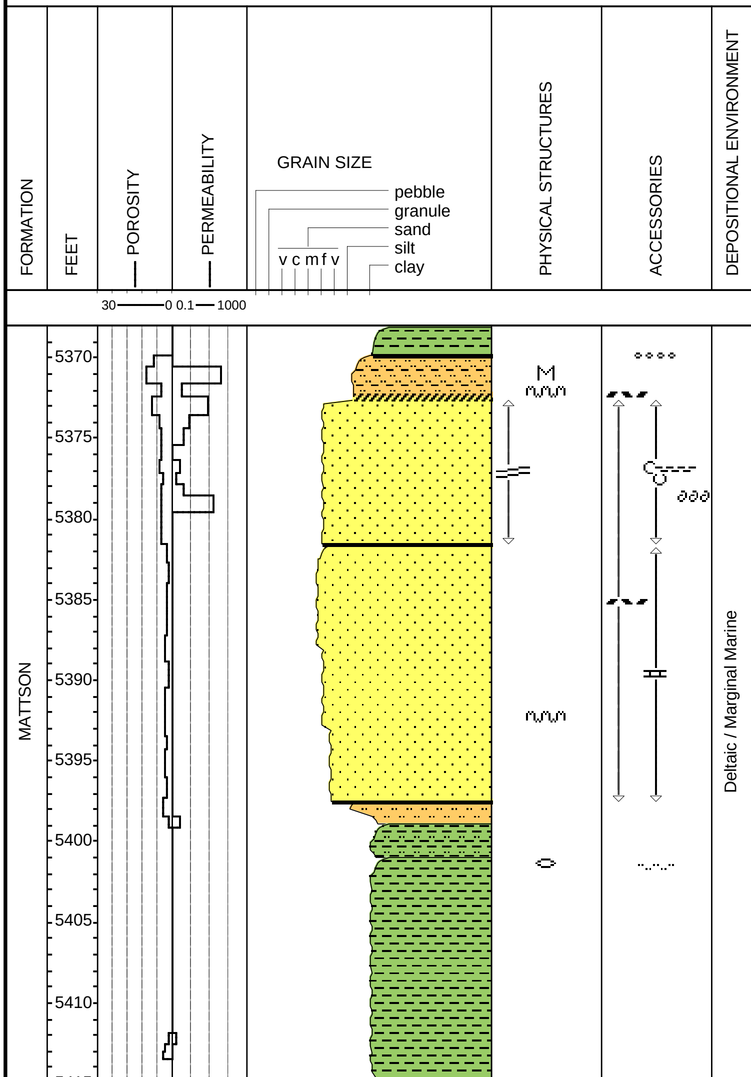
B-21-K 94-O-14

Date Logged: June 1, 2000

Logged by: Brad J. Hayes

Remarks: Core #1: 5368-5415' (Rec. 47')

3.5" core, slabbed.



REMARKS

Dark grey, very fissile. Sharp base with granule layer; few beds of reworked sandstone.

Buff/greenish cast, hard, non-calcareous. Interfingering/gradational base, with some flat mud clasts to core diameter and stylolites.

Pervasive pyrobitumen. Thin flat mud clasts and thin mud beds suggest low-angle bedding.

Lens of medium-grained shell debris

Coarsening-upward aspect; dom. fine with abund. coarser grains. Small rounded mud clasts and shell debris. Pervasively calcite-cemented.

Transition - siltstone to argillaceous silt to silty mud (greenish).

Medium-dark grey; wavy/lenticular silt beds at top, grading down to subfissile, relatively pure.

Aquitaine et al Tattoo

A-28-D 94-O-15

Date Logged: June 1, 2000

Logged by: PETREL ROBERTSON CONSULTING LTD.

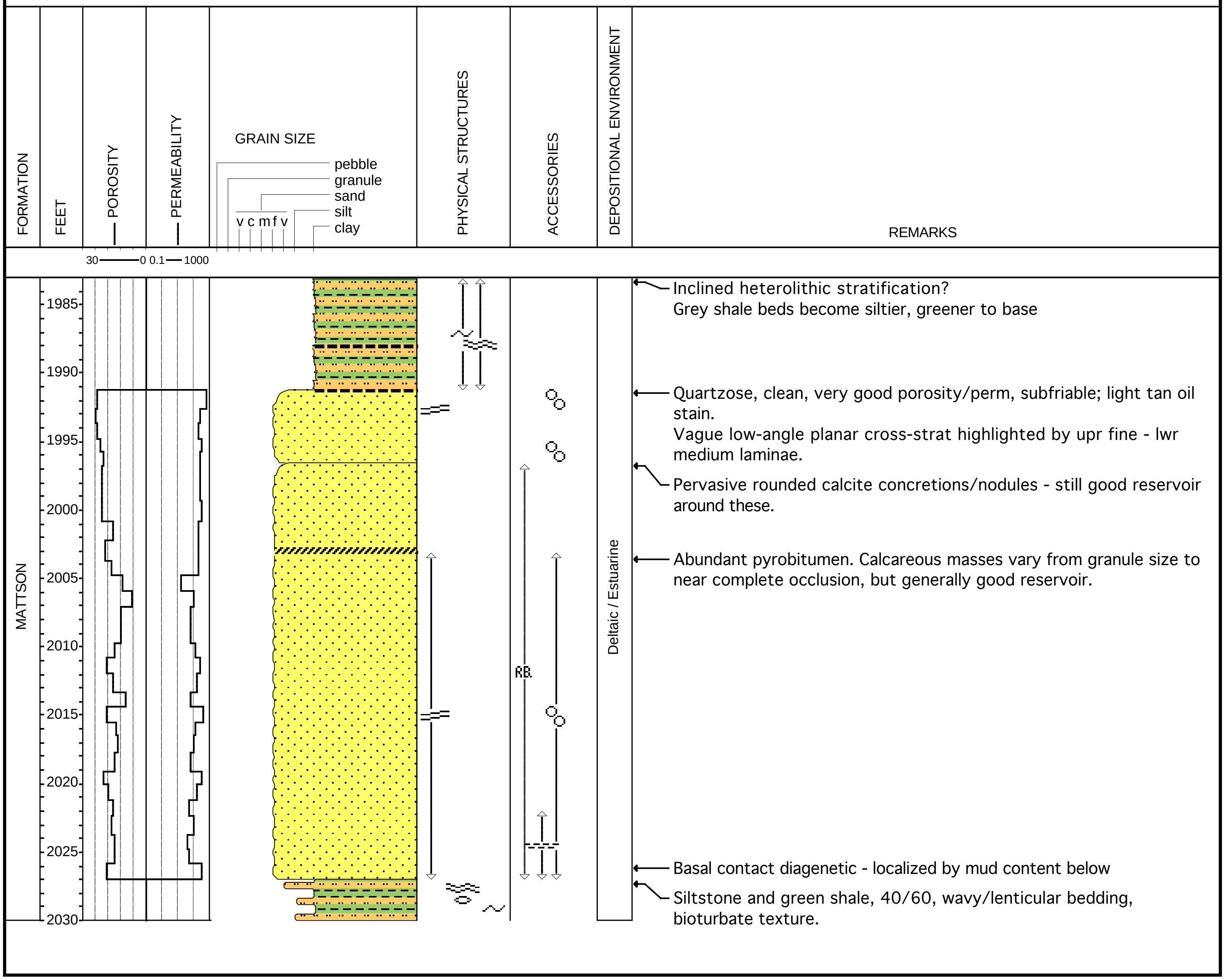
Remarks: Core #1: 1983-2030' (Rec. 47')

Core #2: 2695-2748'

4" core, slabbed.

Core #1: Excellent reservoir at top - are calcite nodules nucleated on shell fragments??

Core #2: not logged in detail - two sanding upward successions, culminating in heterolithic siltstone/shale with minor oil stain.



APPENDIX III

JC Consulting Inc. Report:
Drill Cuttings Petrographic Study

HORN RIVER BASIN AQUIFER CHARACTERIZATION PROJECT
DRILL CUTTINGS PETROGRAPHIC STUDY
(JC Consulting Inc.)

METHODOLOGY and GENERAL OVERVIEW

Our primary purpose was to review rock parameters of potential aquifers through examination of drill cuttings for 63 wells drilled within the Horn River Basin. Samples were supplied by the current operators drilling in the area, and by the Geological Survey of Canada's Core and Sample Division. We were assigned to determine reservoir quality for the purpose of water disposal potential, or as a water source for drilling and completion operations in the shale basin.

Primary targets were the Mississippian Mattson clastics, and the Mississippian Debolt and Rundle carbonates.

A rock description strip log was created for each well, using WellSight Systems Strip log program. It facilitates plotting a lithology graphic and written description, along with porosity and permeability estimation values, pore visibility, pore reduction components, hydrocarbon staining and grain size. Drillstem test intervals and results can also be shown.

Porosity and permeability estimation is based on a variation of the Sneider[1] technique, which compares various measured and observed rock parameters of known rock and compares them to unknown rock. No relevant rock cores were available for this project, and so porosity and permeability estimation was based on previously-viewed rock and work experience. Permeability and porosity values are presented in a more direct format providing estimated value ranges in porosity percentages and permeability in millidarcies rather than 'type' grouping.

The parameters used to identify clastic rock quality and estimate porosity and permeability values are: grain identification, size, shape, consolidation based on quantity and type of intergranular components, primary cements and clay constituents.

It is more difficult to determine representative porosity and permeability values for carbonate rocks, because of their heterogeneous nature. Rock type and primary components are described, along with texture, pore type, and alterations such as dolomitization , silicification and leaching.

Within the Debolt and Rundle, three main rock types were present:

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[1] Sneider, R.M., Sneider and Meckel Associates, H. R. King, H. E. Hawkes and T. K. Davis, 1981. "Methods for Detection and Characterization of Reservoir Rock, Deep Basin Gas Area, Western Canada", SPE 10072.

- Porous to predominantly non-porous wackestone / packstone
- Porous to very porous dolomite and
- Porous silicified/solution zones

LImestones consisted of crypto- to microcrystalline and common fine crystalline limestone, with trace to common bioclastic material, comprising primarily crinoids with common coral and bivalves. Fine to coarse crystalline limestone present in a number of wells had very good intercrystalline porosity, ranging from 3-6%, and permeabilities up to 5+ millidarcies.

Dolomitized intervals exhibited excellent porosity and permeability, and are present as very finely crystalline to coarse crystalline dolomite, with common sucrosic texture and pin-point to large vugular pores with drusy dolomite lining. Porosity in this facies ranged from 3-6% to as high as 8-10%, with permeabilities of less than a millidarcy in the fine crystalline rock to several Darcies in the vuggy material.

In a number of wells, at least one weathered zone was identified, consisting of silicified and commonly argillaceous crinoidal limestone with common very good dissolution porosity and excellent permeability.

The Mattson Formation was also investigated and varied greatly in thickness, from non-existent to very thick, and consisting of very fine- to medium-grained sand, with common carbonate cement and common to abundant glauconite and patchy pyrite. Porosity ranges from 6-12% with permeability ranging from 5-100+ mD, decreasing with depth due to increasing pore-occluding cements.

Both the Debolt / Rundle and the Mattson have good potential as either water sources or disposal zones. DST information indicates in numerous wells the zones are wet.

APPENDIX IV

JMS Geological Consultants Ltd. Report: A Petrographic Study of the Mattson and Debolt Formations

A Petrographic Study of the Mattson & Debolt Formations

Introduction

The main purpose of this study is to evaluate the reservoir quality and fluid-rock sensitivity of the potential aquifer within the Mattson and Debolt Formations from selected well locations in the Horn River Basin, British Columbia.

Upon review of sixty-three well locations, a total of sixty-five samples were evaluated by thin section petrography. Individual drill cuttings were "hand" selected (~10-15 cuttings per thin section slide) based upon review of the interpreted drill cuttings description (JC Consulting Inc.).

The individual drill cuttings were placed on a glass side with a thin film of epoxy. The glass slide was then impregnated with Orasol blue dyed epoxy and pressurized in a cell to harden the epoxy and allow the epoxy to invade the pore space. The sample was thinly cut and diamond polished to grind the slide to a standard 30 micron thickness. The slide was double carbonate stained to determine dolomite (non-stained), calcite (stained pink) and ferroan (dark blue stain) minerals and glass covered slipped to enhance the digital imaging.

In addition to thin section evaluation, six samples were analyzed by scanning electron microscopy (SEM) and three samples were selected for X-ray diffraction (XRD) to precisely determine the rock composition (XRD) and visualize the texture of "fines" and clay minerals within the pore throat areas (SEM imaging).

The SEM analysis (Calgary Rock and Materials Services Inc.) is completed on an Amray 1820 I Digital SEM with an attached energy dispersive spectrometry (EDS) system. The XRD analysis data sheets interpreted from the diffractogram (two-theta) spectra and the XRD methodology is presented under a separate cover (Calgary Rock and Materials Services Inc.); however, the data is summarized in this report.

The thin section petrography summary is shown in Tables 1-1.8 (Debolt) and Tables 2-2.2 (Mattson) and the XRD data is summarized in Table 3 (Mattson & Bluesky). A ternary diagram of the framework composition (Mattson) is shown in Figure 1, porosity versus permeability cross-plots are illustrated in Figures 2 and 3 and the paragenesis of the Debolt Formation is shown in Figure 4.

Representative thin section and SEM images (8x10"), plus macroviews and described thin section and SEM photo plates are presented after the text and tables. Additional SEM Plates are included after the described photo plates (Calgary Rock and Materials Services Inc.).

Enclosure plots, showing comparison images as well as the interpreted drill cuttings description (JC Consulting Inc.) integrated with thin section and SEM images, are included at the back. Listed below is a summary of the well location, depth, formation, lithofacies, estimated porosity and permeability (kmax) for each sample. Note that stratigraphic assignments in the table below have been posted in accordance with the regional stratigraphy developed by Petrel Robertson, but that images in this report are labelled using original public database nomenclature (and hence do not conform to the PRCL stratigraphic scheme in many cases). Also note that these samples are listed in the order that they were presented for analysis.

Well	Depth	Formation	Lithofacies	Porosity	Kmax
*b-14-A/94-O-1	1870.0 ft	Bluesky	Litho A	~6-8%	~0.05-0.3md
b-14-A/94-O-1	1900.0 ft	Upr Rundle	Litho 1	~6-10%	~1-5 md
b-14-A/94-O-1	1960.0 ft	Upr Rundle	Litho 2A	~6-9%	~0.1-0.5md
c-71-I/94-I-13	630.0 m	Debolt	Litho 2A	~2-6%	~0.1-0.5md
*c-67-J/94-I-13	630.0 m	Bluesky	Litho B	~7-10%	~1-5 md
b-72-K/94-O-1	495.0 m	Debolt	Litho 1	~8-12%	~5-200+md
b-72-K/94-O-1	535.0m	Upr Rundle	Litho 2A	~1-3%	~0.05 md
b-86-K/94-O-1	505.0 m	Debolt	Litho 1	~6-10%	~10-200+md

Well	Depth	Formation	Lithofacies	Porosity	Kmax
c-28-D/94-O-1	1160.0 ft	Bluesky	Litho C	~6-9%	~0.1-0.5md
c-28-D/94-O-1	1230.0 ft	Upr Rundle	Litho 1	~6-10%	~5-50+ md
d-90-K/94-O-7	640.0 m	Debolt	Litho 2A	~4-6%	~0.2-0.3 md
*d-83-L/94-O-7	670.0 m	Mattson	Litho 1	~14%	~50 md
d-83-L/94-O-7	715.0 m	Rundle Und	Litho 2	~1-3%	<0.02 md
b-66-I/94-O-8	625.0 m	Debolt	Litho 3	~6-8%	~1-3 md
a-77-I/94-O-8	2080.0 ft	Bluesky	Litho D	~8-14%	~5-50+ md
a-77-I/94-O-8	2170.0 ft	Upr Rundle	Litho 1	~6-9%	~5-50 md
*d-77-J/94-O-8	2180.0 ft	Debolt	Litho 1	~8-10%	~1-5 md
c-71-A/94-O-9	535.0 m	Upr Rundle	Litho 3	~3-6%	~0.05-0.5md
02/d-54-A/94-O-9/03	575.0 m	Upr Rundle	Litho 1	~6-9%	~1-5 md
a-45-A/94-O-3	350.0 m	Rundle Und	Litho 2	~2-5%	~0.05-0.2md
a-37-F/94-O-2	1130.0 ft	Debolt	Litho 1A	~3-6%	~0.05-0.5md
*b-6-G/94-O-7	2180.0 ft	Upr Rundle	Litho 1	~6-9%	~5-50 md
a-27-I/94-O-8	665.0 m	Upr Rundle	Litho 1A	~3-6%	~0.05 md
a-29-B/94-O-9	745.0 m	Upr Rundle	Litho 2A	~2-3%	<0.05 md
a-6-C/94-O-8	1620.0 ft	Debolt	Litho 1A	~6-9%	~1-5 md
a-6-C/94-O-8	1770.0 ft	Upr Rundle	Litho 1	~7-10%	~10-100+md
a-12-H/94-O-9	510.0 m	Upr Rundle	Litho 3	~10-14%	~5-10 md
d-1-I/94-O-9	425.0 m	Upr Rundle	Litho 3	~7-9%	~1-3 md
d-1-I/94-O-9	430.0 m	Upr Rundle	Litho 2A	~3-6%	~0.05-0.5md
d-92-H/94-O-9	475.0 m	Upr Rundle	Litho 1A	~3-6%	~0.1-0.5md
a-45-G/94-O-8	580.0 m	Debolt	Litho 1	~6-9%	~1-5 md
a-45-G/94-O-8	615.0 m	Upr Rundle	Litho 1A	~3-6%	~0.05-0-5md
b-55-B/94-O-15	520.0 m	Debolt	Litho 3	~6%	~1 md
b-70-B/94-O-15	570.0 m	Debolt	Litho 2	~1-3%	~0.05 md
b-76-K/94-O-8 HZ	780.0 m	Debolt	Litho 1	~6-9%	~1-3 md
b-90-J/94-O-8	735.0 m	Upr Rundle	Litho 1	~7-10%	~5-20 md
b-100-G/94-O-8	650.0 m	Upr Rundle	Litho 1	~3-6%	~1-5 md
c-68-C/94-O-15 HZ	515.0 m	Debolt	Litho 2	~1%	<0.02 md
c-89-G/94-O-8	635.0 m	Upr Rundle	Litho 1	~6-8%	~1-5 md
c-A68-B/94-O-15	500.0 m	Debolt	Litho 1A	~4%	~1 md
c-A68-B/94-O-15	730.0 m	Upr Rundle	Litho 1A	~1-3%	~0.05-0.5md
c-100-G/94-O-8	645.0 m	Upr Rundle	Litho 1	~5-9%	~5-50+ md
d-70-J/94-O-8 HZ	730.0 m	Upr Rundle	Litho 1	~9%	~5-50+ md
d-70-J/94-O-8 HZ	790.0 m	Upr Rundle	Litho 1	~6-9%	~1-10+ md
d-85-G/94-O-8	630.0 m	Debolt	Litho 1	~5-9%	~1-20+ md
d-85-G/94-O-8	690.0 m	Upr Rundle	Litho 1	~3-6%	~1-5 md
d-90-G/94-O-8	625.0 m	Upr Rundle	Litho 1	~6-10%	~1-5 md
d-90-G/94-O-8	650.0 m	Upr Rundle	Litho 3A	~5-10%	~5-50+md

Well	Depth	Formation	Lithofacies	Porosity	Kmax
c-67-K/94-O-8	730.0 m	Debolt	Litho 3	~5-9%	~1-5 md
c-67-K/94-O-8	735.0 m	Debolt	Litho 1	~7-14%	~10-100+md
*a-48-J/94-O-9	475.0 m	Debolt	Litho 3	~3-6+%	~1-5+ md
b-18-B/94-O-9	655.0 m	Debolt	Litho 1	~5-10%	~5-10 md
a-27-L/94-O-10	705.0 m	Mattson	Litho 1	~12-14%	~1-5 md
*a-27-L/94-O-10	715.0 m	Mattson	Litho 1	~9-12%	~5-50+ md
a-27-L/94-O-10	750.0 m	Mattson	Litho 1A	~12%	~50 md
b-96-E/94-O-10	1730.0 ft	Mattson	Litho 1	~6-10%	~0.5-3 md
b-96-E/94-O-10	1820.0 ft	Mattson	Litho 1	~7-9%	~1-3 md
b-96-E/94-O-10	2080.0 ft	Mattson	Litho 1	~7-12%	~5-20+ md
b-96-E/94-O-10	2430.0 ft	Debolt	Litho 1A	~3-6%	~0.1-0.5md
c-66-E/94-O-10	580.0 m	Mattson	Litho 1	~8-12%	~1-5 md
c-A92-E/94-O-15	565.0 m	Cret Sst	Litho 1A	~14-20%	~5-50 md
d-93-C/94-P-3	615.0 m	Debolt	Litho 1	~6%	~1-5 md
c-81-D/94-O-15	460.0 m	Fantasque	Litho 1A	~9-12+%	~1-10+ md
d-79-G/94-O-16	300.0 m	Upr Rundle	Litho 2B	~6-12%	~1 Darcy**
a-88-B/94-O-16	500.0 m	Upr Rundle	Litho 1	~3-6%	~1-5 md

**XRD (3 samples) and/or SEM (6 samples)*
***1 Darcy = 1000 md*

Executive Summary

The ***Debolt and Rundle Formations*** are informally subdivided into three main rock types or lithofacies based upon mineralogy. Lithofacies 1 is crystalline dolomite, Lithofacies 2 is mainly lime packstone/wackestone (Dunham, 1962) and Lithofacies 3 is chert. Due to the variability, each lithofacies will be discussed separately.

Lithofacies 1 (Litho 1) is crystalline dolomite. The depositional texture is largely obscured by dolomitization; however, "ghost" textures of dolomitized crinoids and bivalves suggest a precursor lime packstone/wackestone (Dunham, 1962).

Porosity is ~6-12% and is a combination of intercrystalline, vuggy and local intracrystalline (i.e. secondary dissolution of dolomite crystals). Microporosity (non-effective) is ~10% of the total porosity (i.e. ~1/10).

Permeability and reservoir quality is fair to good (~5-50+md) with local very good reservoir quality (>100+md) in areas with extensive interpreted vuggy porosity. The main controls on reservoir quality are the crystal size of dolomite (i.e. pore throat size), the intensity of tightly interlocking crystals, the extent of vuggy porosity and minor pore occluding cements (e.g. dolomite, calcite, anhydrite and bitumen).

A sub-lithofacies of dolomite (Litho 1A) is crystalline dolomite which most likely represents a secondary or later phase of dolomitization (hydrothermal) with tightly interlocking crystals, occasional ferroan dolomite crystals and local saddle dolomite.

Porosity in Litho 1A is ~3-6% and is a combination of intercrystalline, vuggy and local intracrystalline (i.e. secondary dissolution of dolomite crystals). Microporosity (non-effective) is ~10% of the total porosity (i.e. ~1/10). Permeability and reservoir quality in Litho 1A is poor to fair (~0.5-5 md) with reduced reservoir quality due to the higher intensity of tightly interlocking crystals.

Adverse reaction between introduced fluid and the rock matrix in Litho 1 and Litho 1A is expected to be minor due to the lack of water-sensitive (swelling) clay cements and volumetrically insignificant and localized bitumen.

Lithofacies 2 (Litho 2) is lime packstone/wackestone (Dunham, 1962) with an open marine fossil assemblage of crinoids, bivalves, foraminifera, bryozoans and algae.

Porosity is ~1-3% and is microporosity associated with micrite is the pore type. Permeability and reservoir quality is poor (<0.05 md) due to the high volume of blocky spar cement and areas of significant micrite matrix. Litho 2 is non-reservoir.

Two sub-lithofacies of limestone (Litho 2A and Litho 2B) are described based upon mineralogy (Litho 2A) and the porosity development (Litho 2B). Sub-lithofacies 2A (Litho 2A) is a dolomitic and locally silicified packstone/wackestone (Dunham, 1962) with partial selective replacement of micrite with tightly interlocking dolomite crystals and/or micro-quartz (chert). The fossil assemblage is similar to Lithofacies 2.

Porosity in Litho 2A is ~2-6% (locally up to ~9% in the silicified packstone) and is mainly intercrystalline with minor pinpoint vuggy pores. Microporosity is ~10-20% of the total porosity (i.e. ~1/10 up to ~1/5). Permeability and reservoir quality is poor ~0.1-0.5 md) due to incomplete dolomitization and partial silicification, tightly interlocking dolomite crystals as well as the high volume of blocky spar cement and areas of significant micrite matrix. Litho 2A is non-reservoir.

Sub-lithofacies 2B (Litho 2B) is lime grainstone/boundstone (Dunham, 1962) with abundant crinoids and lesser amount of brachiopods, bivalves, foraminifera, bryozoans and algae.

Porosity in Litho 2B is ~6-12% and is a combination of interparticle and vuggy/moldic. Microporosity is <10% of the total porosity. Permeability and reservoir quality is very good (~1 Darcy) due to the coarse size of bioclasts (large pore throats), a low amount of blocky spar cement, lack of micrite and extensive vuggy/moldic porosity. Litho 2B is identified only at d-79-G/94-O-16. Adverse reaction between introduced fluid and the rock matrix is expected to be minor.

Lithofacies 3 (Litho 3) is silicified limestone and/or dolomite with “ghost” textures of fossils occurring within a microcrystalline quartz matrix. The chert facies occur in relationship to karsting, solution and weathering most common at the top of the Debolt Formation.

Porosity is variable (~3-6%, locally up to ~10-14%) and is a combination of solution enhanced intercrystalline and vuggy pore types. Microporosity is ~30-50% of the total porosity (i.e. up to ~1/2 of the total porosity).

Permeability and reservoir quality is generally poor to fair (~0.5-5 md) with local higher permeability (~5-10+md) in areas within enhanced vuggy porosity. Areas of low permeability (<1 md) reflects the fine crystal size of micro-quartz (small pore throats) and poor silica dissolution.

A sub-lithofacies of chert (Litho 3A) is a silicified grainstone with abundant silicified peloids?/oolites and lesser silicified bivalves. Porosity is subequal amounts of interparticle/intercrystalline and vuggy pore types (i.e. solution enhanced). Microporosity is ~30% of the total porosity. Permeability and reservoir quality is fair to good (~5-10+md). Litho 3A is identified only at d-90-G/94-O-8.

Adverse reaction between introduced fluid and the rock matrix in the Debolt Formation is expected to be minor due to the lack of water-sensitive (swelling) clay cements and volumetrically insignificant and localized bitumen.

From thin section examination, the paragenesis in the Debolt Formation (Figure 4) is interpreted as follows:

1) Deposition of limestone (packstone/wackestone & local grainstone) with an open marine fossil assemblage of crinoids, bivalves, foraminifera, bryozoans and algae followed by blocky spar cementation often occurring as syntaxial overgrowths on crinoids (Litho 2).

2) Dissolution of fossils (vuggy porosity) possibly related to karsting, solution and/or weathering (Litho 2B).

3) Dolomitization by low temperature mixing zone conditions (reflux dolomitization) which enhanced reservoir quality by the development of intercrystalline and possible vuggy porosity (Litho 1). The precise timing of vuggy porosity is highly subjective.

4) Silicification of limestone and/or dolomite in relationship to karsting, solution and/or weathering most common at the top of the Debolt Formation (Litho 3).

5) Late stage dolomitization (high temperature hydrothermal) which most likely relates to faulting/fracturing in the basin. (Litho 1A) This type of dolomite is locally ferroan in composition with tightly interlocking crystals resulting in destruction of porosity. Local saddle dolomite cement is also identified (e.g. a-27-I/94-O-8).

There was a lack of evidence in the petrography to show a depositional facies change (i.e. dolomitized packstone/wackestone) between the upper and lower Debolt dolomite sections as well as a lack of depositional facies change between the “porous” dolomite (Lithofacies 1) and the lower quality dolomite (Lithofacies 1A). Dolomite (Lithofacies 1) has the best aquifer potential in the study area.

The limestone facies is largely non-reservoir (exception is “porous” grainstone/boundstone at d-79-G/94-O-16) and the chert facies locally has modest aquifer potential in areas with enhanced vuggy porosity (e.g. c-67-K/94-O-8).

Only one primary lithofacies was observed in the ***Mattson Formation***. ***Lithofacies 1 (Litho 1)*** is lower very fine to upper fine (locally medium) grained, moderately well sorted quartzarenite (Folk, 1968). Framework mineralogy is dominated by monocrystalline quartz (77-91%) with minor amounts of chert (1-3%). Cements include variable amounts of ferroan dolomite (nil-20%), quartz overgrowths (1-6%), kaolinite (nil-4%), pyrite (trace-2%), bitumen (nil-1%) and pore lining clay (trace-1%).

X-ray diffraction clay fraction (670.0m @d-83-L/94-O-7) indicates kaolinite and quartz fines with rare pyrite. Water-sensitive (swelling) clay is absent (Table 3).

Porosity is ~6-12% and primary intergranular (effective) porosity is the dominant pore type. Intragranular microporosity (non-effective) associated with tripolitic (microporous) chert grains plus clay microporosity associated with kaolinite accounts for ~10-20% of the total porosity (i.e. up to ~1/5).

Permeability and reservoir quality is fair to good (~1-5 md, locally 5-50+md). The main controls on reservoir quality are grain size (i.e. pore throat size), volume of cements and the degree of sediment compaction.

A sub-lithofacies of sandstone (Litho 1A) is upper fine (locally coarse) grained, moderate to moderately well sorted sublitharenite (Folk, 1968). A higher chert content (i.e. 8-15%) and local glauconite grains (c-81-D/94-O-15) is characteristic of this Lithofacies 1A (Figure 1). Cements include dolomite (2-8%), quartz overgrowths (1-3%), pyrite (trace-1%), bitumen (local trace) and trace pore lining clay.

Porosity in Litho 1A is ~9-12% (locally ~14-20%) and primary intergranular (effective) porosity is the dominant pore type. Microporosity is ~10% of the total porosity (i.e. ~1/10). Permeability and reservoir quality is good (~1-10 md, locally 50+md) due to the larger grain size (larger pore throats), lower volume of cements and poor sediment compaction.

The Mattson Formation has good aquifer potential (i.e. ~5-50+md) in areas with a larger grain size and lower amounts of dolomite, quartz and kaolinite cements (i.e. Lithofacies 1A and some areas of Lithofacies 1).

Adverse reaction between introduced fluid and the rock matrix in the Mattson Formation is expected to be minor due to the low clay content, volumetrically insignificant and localized bitumen and the lack of water-sensitive (swelling) clay.

Prepared by:

Jim M. Stepic, P.Geol.
JMS Geological Consultants Ltd.

APPENDIX V

Canadian Discovery Ltd. Report: Hydrogeology

Canadian Discovery Ltd.

GEOSCIENCES BC - HYDROGEOLOGIC CHARACTERIZATION OF HORN RIVER BASIN AQUIFERS

Prepared for:
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EXECUTIVE SUMMARY

The need for substantial volumes of water to be used for shale gas well completions in the Horn River Basin exists. In addition, a suitable non-potable disposal zone for produced water needs to be identified.

The overall objective of this study is to characterize aquifer hydrogeology, deliverability, resource and storage properties, analyze their suitability for supporting HRBPG shale gas operations and provide recommendations for future work. However, since little to no data exists for shallow Quaternary-aged aquifers, the focus of this study is deeper, Mississippian and Cretaceous-aged aquifers, with particular focus on aquifers within the Mississippian Debolt Formation and Rundle Group.

Data was obtained through a mix of public formation pressure and water chemistry databases and proprietary pressure, chemistry and deliverability data provided by members of the HRBPG.

Pressure/hydraulic head and formation water chemistry data from the Debolt-Rundle and basal Cretaceous sandstones are all very similar suggesting that there may be a connection between aquifers within these units. As well, hydraulic head and pressure over depth mapping strongly suggest there is an intervening aquitard between Mississippian-Cretaceous aquifers and the ground surface.

Total dissolved solids concentrations of formation waters within the Mattson, Debolt-Rundle and basal Cretaceous sandstones all exceed standards for safe drinking water, making the formation water non-potable.

H_2S has been identified in gas samples from the Mattson Formation, Debolt-Rundle Group and basal Cretaceous sandstones.

On a per-DLS section basis (~ 200 ha) and using some significant assumptions with respect to porosity, water volume within the Debolt-Rundle group exceeds 10,000,000 m^3.

Permeability analysis of Debolt-Rundle cores, DSTs and pumping/injection tests reveal that permeabilities can exceed 10,000 mD. However, most of the high permeability data came from analysis of pumping/injection data, suggesting this form of test was more capable of intersecting these high permeability zones.

There is little correlation between wells where high permeability was measured and the enhanced reservoir mapping provided by Petrel Robertson.

Three test cases for transient well deliverability were run in order to provide ballpark estimates of pumping rates for a single well in a Debolt-Rundle aquifer. The three cases were: a high deliverability case based on a aquifer with high permeability and large total area, a low case based on an aquifer with relatively low permeability, and high deliverability case base on an aquifer with high permeability but a much smaller total area.

According to the two high cases, a single well flowing constantly for two months could produce between 200,000 and 900,000 m^3 of water. This volume would be sufficient enough to support 15 to 50 well completions if a per completion volume of 16,000 m^3 is assumed.

Over a two-month period, the low-well deliverability case could not provide sufficient water for a single completion.

A single injection rate forecast was conducted for a well with relatively high permeability. At the beginning of injection, the injection rate was in excess of 10,000 m^3/d but the rate drops to less than 100 m^3/d in after twelve months. The cumulative volume of water injected over this twelve-month period would be nearly 800,000 m^3.

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APPENDICES

1.0 INTRODUCTION

Canadian Discovery Ltd. (CDL), with the support of Matrix Solutions Inc. (Matrix), is pleased to provide the results of the study entitled “Hydrogeologic Characterization of Horn River Basin Aquifers”. This study was completed using results from geologic mapping provided by Petrel Robertson Consulting Ltd. (Petrel).

Geoscience BC and the Horn River Basin Producer’s Group (HRBPG) have identified the need for substantial volumes of water to be used for completions in their ongoing shale gas developments. In addition, the need exists for a suitable non-potable disposal zone for produced water.

The overall objective of this study is to characterize aquifer hydrogeology, deliverability, resource and storage properties, analyze their suitability for supporting HRBPG shale gas operations and provide recommendations for future work.

The most environmentally acceptable source for this water is from aquifers containing non-potable water. For the purpose of this study, potential aquifers within the Mississippian Rundle Group, the Mississipian Mattson Formation and basal Cretaceous sandstones have been identified by Geoscience BC as potential targets.

It became apparent early on during the geological mapping phase of this study, that the Rundle Group would likely have the highest permeability and therefore much of the detailed hydrogeologic mapping is focused on this unit.

Potential, shallower Quaternary aquifers were not included in this study due to a lack of available public data. As well, the Cretaceous Chinkeh Formation, located in the Liard Basin just west of the Horn River Basin, was not studied because of the gas-charged nature of this Formation.

The outline of the study area can be found in Figure 1.

2.0 DATABASE

Data used in this study was a mix of public and proprietary data provided by members of the HRBPG. Pressure data was obtained from drill stem tests and proprietary pressure build-ups taken prior to pumping/injection tests.

Pressure data from public gas well build-ups and absolute open flow tests (AOFs) were not included in this study, due to the fact that most were performed in gas caps of conventional gas pools. Once converted to hydraulic head, these data would not provide an accurate representation of the pressure regime in the underlying aquifer.

Gas and water chemistry data was obtained from public well files compiled in the Geofluids database.

Public core data for the Rundle Group was obtained from Accumap.

Permeability and deliverability data were obtained both from proprietary pumping/injection test analyses and from analysis of DST flow and build-up graphs.

3.0 METHODS

3.1 Data Screening

3.1.1 DST Quality Coding

Fluid pressures measured by DSTs may not reflect true undisturbed formation pressures for a variety of reasons, including:

1. Mechanical error/failure during the test.
2. Inaccurate or incomplete recording of test data.
3. Formation pressure modification during drilling (e.g., supercharge).
4. Improper extrapolation of the pressure test data.
5. Production induced drawdown.

Pressures exhibiting effects 1 through 4 can be recognized and screened-out by using strict quality control guidelines. Quality codes, which relate to the success of the test and the confidence that can be placed in the accuracy of the pressure, have been assigned to the DSTs and allow the interpreter to quickly and easily differentiate between the highest quality pressures (coded as A and B quality) and those which are less reliable (coded as C to D quality) and those which are not usable (coded as E, F and G quality). The good quality pressures are favoured when building an interpretation, and the less reliable pressures are only used when absolutely necessary, in areas where data density is sparse. For most of the pressure tests, initial reservoir pressures were determined by Horner analysis, where there was sufficient shut-in pressure build-ups for extrapolation.

Table 1. List of Drill Stem Test Quality Codes and Criteria

Quality Code	Quality Rating	Test Characteristics
A	High Quality	Test mechanically sound, both shut-in pressures have stabilized.
B	Requires Extrapolation	Slight mechanical difficulties, shut-in pressures not fully stabilized, but pressures have been extrapolated and should be accurate.
C	Requires Extrapolation, use with caution	Some mechanical difficulties apparent, shut-in pressures not fully stabilized, but pressures have been extrapolated and can be used with caution.
D	Test Results Questionable	Test not mechanically sound and pressures have not stabilized enough to obtain reasonable extrapolation, thus the results are questionable.
E	Low Perm, High Pressure, Low Quality	Low permeability, low pressure but problems encountered throughout test and/or unable to extrapolate. Pressure should NOT be used.
F	Low Perm, High Pressure, Low Quality	Low permeability, high pressure but problems encountered throughout test and/or unable to extrapolate. Pressure should NOT be used.
G	Misrun, Low Quality	Severe mechanical difficulties: packer failure, tool failure, plugged tool. Pressures invalid if present.
E, F, G	Low Quality	See E, F, G above.

Once the initial pressure screening was complete, formation pressure data was converted to hydraulic head and mapped. It was during this stage that pressure data affected by production was identified and removed from the dataset. Also during this stage, pressures overestimating hydraulic head due to their tested interval location in gas pools were identified and removed.

Enclosures 1 to 3 are maps showing the final public DSTs used in this study for the Debolt-Rundle, Mattson and basal Cretaceous sandstones.

Appendix 1 includes all pressure data used in this study.

3.1.2 Water Chemistry

All water analyses for a given map unit were screened according to chemistry in a spreadsheet format by calculating the following ratios:

Table 2. Primary Water Screening Criteria

Compound Ratio (meq)	Unacceptable Values	Classification
Na/Cl	<0.7 or >1.2	GelChem Mud Filtrate
Na/K	<125	KCl Mud Filtrate
Na/Cl+HCO_3	<0.7 or >1.2 and Na/Cl >5.0	GelChem Mud Filtrate

Other rejection cutoffs included:

110% < [Cations-Anions] / [Cations+Anions] *100 < 90%	Ionic Imbalance
Na or Cl = 0	Incomplete Analyses
0.9 > Density >1.1	Alcohol Contaminant
Fe (meq) > 0.5	Acid wash/Completion Fluid
SO_4 > Cl	Inhibitor Mud

Remaining analyses were then viewed in geoFluids and further classified using the STIFF diagram, sampling point, recovery description, salinity and pH. Observations such as the range of salinities for a given area and map unit were taken into account. In some cases analyses were labelled as “Miss-classified Formation” when salinities were orders of magnitude larger than the neighbouring analyses. Recovery descriptions were used when the chemistry was questionable. Larger recoveries (nearing 1,000 m) were assumed to represent formation water, while small recoveries such as 10-20 m were often classified as mud filtrates.

Appendix 2 includes all water chemistry data used in this study.

3.2 PE Graphing

A Pressure versus Elevation (PE) graph is a tool, which helps in determining pressure connections between formations and also provides an idea of the magnitude of hydraulic gradient for an aquifer in an area.

Good quality pressures and elevation (mASL) that they were recorded at for Cretaceous, Mississippian and Devonian formations were plotted on a PE graph.

3.3 Hydraulic Head Mapping

Hydraulic head was calculated using the following equation:

Head = P/g+E

Where:
P = Pressure (kPa)
g = Pressure Gradient (kPa/m)
E = Elevation of the pressure recorder (mASL)

Although many pressure values recorded are gauge pressure, in the pre-digital era (circa 1980), pressures were recorded as guage pressure with atmospheric pressure equal to zero. Later digital gauge pressures may be absolute or gauge. For this reason, all pressures are considered to be absolute, fully realizing that some pressures may be gauge and others absolute. Normal atmospheric pressure is approximately 100 kPa and using an approximate pressure gradient of 10 kPa/m, this could possibly represent and a calculation error of 10 m. Knowing this error could exist, a 20 m contour interval was used when mapping hydraulic head across the study area in order to minimize the effect it could have on the contour distribution.

3.4 Pressure Over Depth (P/D) Mapping

Pressure over depth is a measure of overpressuring or under pressuring (using an approximate 10 kPa/m gradient) and is very useful when planning drilling programs.

Also, pressure divided by recorder depth (P/D) can give an idea of how topography may effect the hydraulic head distribution in an aquifer. An aquifer with fairly consistent P/D values all nearly equal to 10 kPa/m, suggests an aquifer may be unconfined (i.e. lacking an overlying cap of tight rock). Hydraulic head in an aquifer with diverse P/D values across its areal extent, is likely not strongly influenced by topography. As well, the aquifer is likely confined (has an overlying cap of tight rock) and is to a fair degree, isolated fromshallow groundwater and surface water.

Pressure over depth values were calculated by dividing good-quality pressures by the recorder depth.

3.5 Available Head Mapping

Available head is a measure of the water column height that is available for pumping before the potentiometric surface is drawn down enough that it intersects the top of the completed zone. It is essentially, the difference in elevation between the potentiometric surface and the top of the completed zone at the wellbore.

Since the top of every completion is likely to be different, for the purpose of this mapping, the elevation of the top of completion is assumed to be equal to the elevation of the pre-cretaceous unconformity for each well.

Hydraulic head was estimated for each well using the hydraulic head contour map generated for that unit.

3.6 Formation Water Chemistry Mapping

Total dissolved solids (TDS) was mapped as indicator of formation water salinity and potability. Screened TDS data were plotted and contoured. When one well had multiple good-quality values, the value that best fit the observed trend was honoured and the other values ignored. However, the ignored values were still included on the map in order to provide insight into the range of TDS values that can occur in a formation.

3.7 H_2S Chemistry Mapping

Hydrogen sulphide gas is a potential by-product of water production in the area. For this reason, H_2S concentrations from publicly available gas chemistry analyses were plotted on a map.

H_2S concentration was plotted for Devonian to Cretaceous formations on the same map with the sampled formation posted below the H_2S concentration value.

Appendix 3 contains the gas chemistry data used in this study.

3.8 Resource Volume Mapping

The volume of water in a confined aquifer is contained in the primary and secondary pore spaces and is released from storage by dropping the pressure at the sandface of a well. In cases where aquifers or reservoirs are unconfined, the pore spaces can be pumped dry as the water level drops below the completed interval on an area wide basis but in confined aquifers, pore spaces cannot be pumped dry until all water contained in storage is first released.

Since the focus of this study is primarily the Debolt-Rundle group, resource volume mapping was constrained to the Debolt-Rundle group.

Reservoir Volume

Reservoir volume can be calculated using the following equation:

$V = A \times F \times b$

Where:

A = area (m2)

F = porosity

B = thickness (m)

Reservoir volume was calculated using the enhanced reservoir thickness and Pre-Cretaceous-Banff isopach values provided by Petrel. These thicknesses were then multiplied by an assumed porosity, described below.

Since average porosity values for both the enhanced reservoir thickness and total isopach were unavailable, three different reservoir volume categories were created using an assumed average porosity of 3%, 6%, and 9%. For the rest of the Debolt-Rundle Group not considered enhanced reservoir, an assumed average porosity of 2% was used.

Reservoir volumes were calculated on a per section basis (2,589,968 m^2). Although the water source and injection wells may not be installed on a one-per-section basis, a standard area was need for this calculation and a DLS section is a common unit of well spacing in the oil and gas industry.

Water Volume Contained in Storage

Specific storage S_s is the amount of water per unit volume of a saturated formation that is expelled from storage due to the compression of the aquifer and expansion of water per unit change in hydraulic head, as the reservoir pressure declines due to production.

The following equation developed by Jacob (1940) and Cooper (1966) expresses specific storage

$S_s = {}_w g(\; + \; b)$

Where:

${}_w g$ = specific weight of water or density pressure gradient (kg/m^2s^2 or $N/(m^2 \cdot m)$)

= aquifer compressibility (m^2/N or Pa^{-1})

= porosity

b = water compressibility (m^2/N or Pa^{-1})

For the purposes of this study the specific weight of water was calculated for water with a TDS of 20,000 mg/L at 25c which is equal to 9927.72 kg/m^2s^2. Aquifer compressibility was considered equal to 3.3×10^{-10} m^2/N and water compressibility was equal to 4.5×10^{-10} m^2/N. Both are industry-wide accepted values for these variables. Like the reservoir volume mapping, an average porosity was needed for this calculation and once again three scenarios using 3%, 6% and 9% were used.

The storativity of a confined aquifer is a product of the Specific Storage and the aquifer thickness. This accounts for all water released by the compressibility of the aquifer and the formation water across the entire thickness of the aquifer. The equation for storativity is as follows:

$S = bS_s$

Where:

b = aquifer thickness (m)

Total water volume released from storage assuming all available head is drawn down during pumping. For the purposes of this study, the aquifer thickness was considered equal to the thickness of the total enhanced reservoir as provided by Petrel

$V_w = SADh$

Where:

A = area

Dh = change in hydraulic head (m) – available head

For the purpose of this study, the area used was equal to 2,589,988 m^2 which is equal to the area of one DLS section (1 $mile^2$), a standard area used in the oil and gas industry when calculating drainage of hydrocarbon pools.

Appendix 4 contains all resource volume data.

3.9 Permeability Analysis

Permeability values were obtained from publicly-available core analyses, analyses of publicly available DST flow and build-up curves, and analyses of pumping and injection tests run by the HRBPG.

3.9.1 Core Data

Porosity-permeability cross-plots were made from available core analyses. Cores provide very valuable information on the lithology and facies of the reservoir, but characterize the permeability, at best, for an 18 cm, 4.5 inch cylindrical volume. For reservoirs that are very heterogeneous the core permeabilities have to be scaled in order to determine deliverability. The scaling factor for the Debolt reservoir in the study area is not known at this time.

Appendix 5 contains the core data used during this part of the study.

3.9.2 DSTS

Debolt-Rundle and basal Cretaceous sandstone drillstem tests were analyzed to determine the permeability of the aquifer within a volume that was sufficiently large enough to give a reasonable estimate of the permeability and deliverability of the reservoir. .

Initially, a summary table for each drillstem test was written (Table 1). This table contains rates determined for the DST flow periods, an assessment of test quality and verification of the test recovery. The test interval is checked and corrected, if necessary, and values for productive thickness and porosity, determined from log analysis, are listed. Increments for the test charts were entered into a separate table (Table 2) and were transferred to the Fekete F.A.S.T. WellTest program for reservoir evaluation and simulation. In the case where increments were not available, these were read by digitizing the copy of the chart provided with the drillstem test report. Figures 2, 3 and 4 show the results from a drillstem test analysis.

3.9.3 HRBPG Well-Test Analysis

Well test data from pumping/injection tests from members of the HRBPG were collected and analysed for permeability. These well tests were only conducted in the Debolt-Rundle Group and not conducted in wells completed in basal cretaceous sandstones. In some cases, data from HRBPG member well tests included a permeability and/or deliverability analysis. When this was the case, the permeability value was added to the database and no further analysis was conducted. For wells, 200/d-090-G/094-O-90/00, 200/c-067-K/094-O-09/00, and 200/a-077-K/094-O-08/00, permeability analysis were conducted by Matrix. Detailed explanation of the methodology used by Matrix can be found in appendices 6 and 7.

Finally, well test data from well 200/a-002-J/094-O-09/00 were analyzed in-house at CDL using methodology similar to that used during the drillstem test analysis.

No analysis was made on a Mattson Formation test at 200/aD1-L/094-O-15/00. During pumping, significant gas was produced causing the pump to shutdown. As such, no consistent and measurable flow rate was recorded. Without this information, no permeability analysis could be made.

3.10 Deliverability Estimates

Well deliverability is difficult to estimate due to uncertainties in development plans. Variables such as how many wells and their spacing distance will greatly affect how much water can be produced or injected into a formation. In order to be able to accurately estimate deliverability, different development scenarios would need to be run in a detailed numeric groundwater or reservoir model. However, in order to come up with a ballpark estimate of deliverability, CDL ran some test case scenarios that are detailed below.

Deliverability was determined for three reservoir models that are based on the DST analyses and injection tests of the Debolt-Rundle aquifer and represent likely reservoir types for the Debolt Formation in the Horn River Basin. The three scenarios were a high deliverability model, a low deliverability model and a model that assumes the enhanced reservoir has a channel-like shape and therefore had no low-flow boundaries at a certain distance away from the wellbore.

In addition to the above scenarios, Matrix provided Q20 estimates of deliverability as part of their analyses of wells 200/d-090-G/094-O-08/00, 200/c-067-K/094-O-08/00, and 200/a-077-K/094-O-08/00 using the Farvolden (1959) method. Q20 is essentially the rate at which a well can flow for 20 years where the available head decreases to no less than 70% of its original amount. Detailed discussion of the above methods can be found in Appendices 6 and 7.

Q20 = (0.68)(T) (HA) x (0.7)

Where:
Q20 = long term deliverability [m3/d]
T = transmissivity [m2/d]
HA = available head (equivalent hydraulic head minus
elevation of top of screen interval)

4.0 RESULTS AND DISCUSSION

4.1 PE Graphing

The PE graph can be found in Enclosure 4. DST pressure data is broken up between Cretaceous, Mississippian-Rundle, Mattson, Banff-Exshaw, and Devonian data.

Water lines on a pressure versus elevation graph represent the change of pressure with elevation under hydrostatic conditions and have a slope equal to the specific weight of the fluid. In the Horn River Basin, Cretaceous, Mississippian and Devonian groundwater is flowing and not static, therefore interpreting a single water line for data groups based on formation age is not technically possible. However, hydraulic head gradients in the Horn River Basin are sufficiently low enough, that water lines are able to sufficiently illustrate similarities between data groups. In this case, water lines with a slope of 10 kPa/m were used to determine general similarities/differences between the

Cretaceous, Mississippian-Rundle, Mattson, Banff-Exshaw, and Devonian data.

For the most part, Cretaceous and Mississippian Rundle data plot in the same pressure-elevation space, while underlying Banff-Exshaw data has more scatter (no pressure gradient line interpreted) and is on average, at a lower pressure. Mississippian Mattson formation pressure data plot on a general water gradient line, which is of slightly lower pressure than the Cretaceous-Mississippian water gradient line in the Horn River Basin proper.

Devonian Jean-Marie pressure data have significant scatter and underlying Muskwa, Slave Point and Muskeg formation pressure data plot on two, general water lines which are different from the overlying Cretaceous-Mississippian and Mattson water lines.

Since pressure data from the Rundle Group and overlying basal Cretaceous sandstones plot in similar PE space, a pressure connection between these units can be inferred and no aquitard that restricts flow between them exists. For this reason, the Rundle Group and the basal Cretaceous sandstones can be considered to be one hydrostratigraphic unit (HSU).

Underlying this HSU, is the Banff-Exshaw formation. Since the formation pressure data from this formation is significantly scattered and does not plot in similar PE space as the Rundle-Cretaceous data, it is likely that the Banff-Exshaw formation is the underlying aquitard for the Rundle-Cretaceous HSU. However, a more definitive study would have to be done to prove this.

The location of overlying aquitard for the Rundle-Cretaceous HSU is at this point, not known since there was no available formation pressure data for units above the basal Cretaceous sandstones. However, it is likely an upper bounding aquitard exists and the reasons for this will be explained during the Hydraulic Head and P/D results and discussion section.

4.2 Hydraulic Head Mapping

Enclosures 5 to 7 detail the results of the hydraulic head mapping for the Debolt-Rundle, Mattson Formation and basal Cretaceous sandstones. Hydraulic Head data are located in Appendix 1.

Hydraulic head in the Debolt-Rundle group is highest in the south and southeast portions of the study area and lowest in the north. Values range from above 540 mASL to below 400 mASL. Across the Horn River Basin proper, from 094-J-15 to 094-O-15, hydraulic head drops from 480 mASL to 400 mASL in a South to North direction. This represents an approximate hydraulic head drop of 80 m across an estimated 120 km, which is equal to a hydraulic head gradient of 6.7×10^{-4} m/m.

Hydraulic head distribution in the basal Cretaceous sandstones is very similar to the Debolt-Rundle group. Highest head values occur in the south and southeast parts of the study area. As well, hydraulic head drops from 480 mASL to 420 mASL across approximately 100 km, which equates to a hydraulic head gradient of 6×10^{-4} m/m, also similar to the Debolt-Rundle.

The similar hydraulic head distributions between the basal Cretaceous sandstones and the Debolt-Rundle group further reinforces the previous observation that these two units can be considered one hydrostratigraphic unit and there is likely no major aquitard separating these two units.

Hydraulic head in the Mattson Formation is highly variably, ranging from 404 mASL in the north to 526 mASL in the northwest. In some instances, such as in L/094-O-10, head can change rapidly (465 mASL to 412 mASL in less than 1 km). The high variation in hydraulic head could be due to faulting in the Bovie Lake fault zone, vertical variability or the occurrence of lenticular flow units within the Mattson formation itself. Due to the high variation and lack of detailed mapping of structural elements within the Mattson, no contouring of the Mattson hydraulic head data was done, since it would not be possible to provide an accurate interpolation of this data.

4.3 Pressure over Depth (P/D) Mapping

Enclosures 8 and 9 are the results of the P/D mapping for the Debolt-Rundle and basal Cretaceous sandstones. P/D data are located in Appendix 1.

P/D values in the Debolt-Rundle Group range from above 12 kPa/m to below 6 kPA/m. Highest values can be found in the southeast corner of the study area, while lowest values can be found in the centre of the study area. P/D values in the basal Cretaceous sandstones are again, very similar to values from the Debolt-Rundle Group and range from above 11 kPa/m to below 7 kPA/m.

Highest values can be also found in the southeast corner of the study area, while lowest values can be found in the centre of the study area.

The P/D mapping of the Debolt-Rundle and basal Cretaceous sandstones confirms the presence of an aquitard between these units and shallow surface water. If the P/D values were consistently in and around 9-10 kPa/m for these units then one might conclude that formation pressure was affected by surface water and shallow groundwater. Instead, P/D values vary considerably throughout the area.

Figure 1 includes the topographic relief of the study area and it can be noted that areas of high P/D tend to correspond to topographic lows, while areas of low P/D tend to correspond to topographic highs. This suggests that pressure within the Rundle and basal Cretaceous units remains fairly constant and the more significant variable controlling P/D is the topography or the depth to these units. Therefore, topography is not affecting the pressure or hydraulic head in these units because there is a sufficient low permeability unit between the surface and the Debolt-Rundle-Cretaceous HSU, which impedes vertical flow.

4.4 Available Head Mapping

Enclosure 10 is the Available Head map for the Debolt-Rundle group. Available head was only mapped for the Debolt-Rundle Group since its main use is for the formation water volume calculations and no water volume calculations were made for other units due to a lack of porosity data. Available head data are located in Appendix 1.

Available head is highest in the southwest, where it is 700 m and decreases to north to less than 250 m. The contour pattern of available head data correlates well with the pre-Cretaceous unconformity structure map. This is understandable since hydraulic head has approximately 150 m of variation while the structure of the pre-Cretaceous unconformity can vary by more than 700 m across the study area.

Areas where available head is the highest provide in general more stored water volume for production than areas where available head is low.

4.5 Formation Water Chemistry Mapping

Enclosures 11 to 13 are the Total Dissolved Solids Maps for the Debolt-Rundle Group, Mattson Formation and basal Cretaceous sandstones. Formation water chemistry data can be found in Appendix 2.

Total dissolved solids in the Debolt-Rundle group ranges from over 40,000 mg/l in the southeast to under 15,000 mg/l in I/094-O-08. Over most of the study area, TDS in the Debolt-Rundle is between 20,000 and 25,000 mg/l.

Total dissolved solids values in the basal Cretaceous sandstones are once again, similar to values found in the Debolt-Rundle. TDS ranges from over 35,000 mg/l in the southeast to under 15,000 mg/l in 094-P-12. However, over the Horn River Basin proper, there are little to no water chemistry analyses for the basal Cretaceous.

In the Mattson Formation, TDS values range from 17,000 mg/l to over 70,000 mg/l. Due to sparse data coverage and the large data range, Mattson TDS values were not contoured.

According to the Guidelines for Canadian Drinking Water Quality (1996), water with a TDS concentration above 500 mg/L can be considered non-potable. Therefore, formation water from the above three units can be considered non-potable throughout the study area.

4.6 H_2S Chemistry Mapping

Enclosure 14 is the H_2S concentration map for the study area and the associated data can be found in Appendix 3.

HRBPG well files also include some H_2S concentration values from both gas analysis and daily reports during pumping and injection tests. These values are also included in Appendix 3.

H_2S concentrations (as percent) are highest in Devonian gas pools where they can sometimes exceed 0.05 by mole fraction (50,000 ppm). In the shallower Mississippian and Cretaceous gas pools, concentrations are less than 0.01 by mole fraction (10,000 ppm).

It should be noted that low-level (< 1 by mole fraction, < 10,000 ppm) concentrations of H_2S have been measured in the Debolt-Rundle Group and basal Cretaceous sandstones in the study area and in particular in and near areas where water source well tests have been conducted.

Also, in the western part of the study area, H_2S has been measured in the Mattson Formation.

An H2S concentration of 10 ppm is considered the safe daily working limit before respiratory equipment is required. When H_2S has been detected in HRBPG test wells, it has been at concentrations in excess of 100 ppm. When testing Mississippian and Cretaceous pumping/injection wells in the Horn River Basin, proper H_2S safety precautions need to be taken.

In addition, Hydrogen Sulphide is also a weak acid when dissolved in water that can corrode metal. The rate at which H_2S corrodes metal is dependant on pH, temperature, production rate and the concentration of H_2S. Pumping and injection infrastructure should be designed with this problem in mind.

4.7 Resource Volume Mapping

Enclosures 15 to 17 are the resource volumes maps using 3%, 6% and 9% average porosities and the associated data can be found in Appendix 4.

Total water volume on a per section basis is on the order of 10,000,000 m^3, with some localized areas with excesses of 50,000,000 m^3 of total water. The majority of the water volume is generally derived from the low-porosity, non-enhanced reservoir portion of the pre-Cretaceous unconformity to Banff unit since the isopach of this unit tends to be much larger than total enhanced reservoir isopach. Over the entire study area, an area equal to 1,578,901.5 ha, the volume of water contained in the non-enhanced reservoir of the Mississippian carbonates is roughly 80 x 10^9 m^3.

Total enhanced reservoir water volumes range from 0 m^3 per section, where there is no enhanced reservoir, to over 10,000,000 m^3 per section in D and E/094-P-13 where the thickness of total enhanced reservoir can be greater than 70 m. Obviously, water volume calculated for the enhanced reservoir is dependent on what average porosity is used, but regardless of whether 3, 6 or 9%

porosity, the general magnitude of reservoir volume is similar. Over the entire study area, which has a size equal to 1,578,901.5 ha, the reservoir water volumes are approximately 5 x 10^9, 10 x 10^9 and 15 x 10^9 m3 for 3%, 6% and 9% porosities, respectively.

Water volume kept in reservoir storage, which is the volume that is available for production, is much less than the enhanced and non-enhanced reservoir volume.

4.8 Permeability Analysis

Permeability data for the Debolt-Rundle Group can be found in Appendix 8 and on Enclosures 18 and 20. Permeability data for the basal Cretaceous sandstones can be found in Appendix 9 and on Enclosure 19.

4.8.1 Core Data

Figure 5 is a permeability versus porosity cross-plot for Debolt-Rundle Group cores and the data used to construct this cross-plot can be found in Appendix 5.

Permeability data from cores are mostly below 10 mD and there is a large portion below 1 mD. There are some data greater than 100 mD and one datapoint is greater than 1000 mD.

The permeability data from cores is likely underestimating the permeability for the Debolt-Rundle Group. As will be seen below, permeability data calculated from DSTs and pumping/injection tests is on average, much higher than data derived from core analyses. The reason for this is core analyses are simply unable to account for macro porosity features such as fracturing and karsting. As well, the higher permeability zones in the Debolt-Rundle Group are fractured/brecciated and would therefore be hard to core, which means there is little core permeability data available for these higher permeability zones.

4.8.2 DST Data

Appendix 8 contains permeability data derived from DST analysis and Enclosures 18 and 19 detail how this data is distributed in the Debolt-Rundle Group and basal Cretaceous sandstones. Figures 1, 2 and 3 show the results from a DST analysis.

The maximum permeability measured was from 200/b-006-G/094-O-10/00 with a permeability of 8,038 mD. The minimum permeability measured was 0.1 mD, which was from a DST performed in 200/c-015-E/094-P-10/00.

4.8.3 HRBPG Well-Test Analysis

Permeabilities measured during pumping/injection tests of the Debolt-Rundle tended to be much higher than those measured in both core and DST analyses and these are also included in Enclosures 18 and 20.

The highest permeability measured was 39,800 mD from a test conducted in 200/b-016-I/094-O-08/00. The lowest permeability measure was 0.1 mD from a test conducted in 202/d-094-A/094-O-08/00. However, this was the only pumping/injection test that measured a permeability less than 1,000 mD.

A final comparison of all three datasets can be found in Figure 6. It is no surprise that the lowest permeability values tend to come from core analyses and the highest values come from DSTs and pumping/injection test analyses.

DSTs and pumping/injection tests have a larger radius of investigation than core analyses, whose radius of investigation is limited to the radius of the core. A larger radius of investigation increases the chance that some macro-permeability feature, such as a fracture or in this case, a dolomitized zone that is considered the enhanced reservoir, will be encountered

Enclosure 20 shows the Debolt-Rundle permeability data overlain on the porosity thickness map of the total Mississippian carbonates, which was provided by Petrel. This overlay shows little to no correlation between high permeability and thicker enhanced reservoir. Any correlation between permeability and porosity-thickness is likely being overshadowed in permeability variatibility due to test type variation. If all permeability data were derived from pumping/injection test analyses for example, then a correlation may be visible between permeability and porosity-thickness may be visible.

4.9 WELL DELIVERABILITY

4.9.1 Results

The model for the high deliverability case is based on the Debolt reservoir in blocks I and J in 94-O-8 and the injection tests for the Encana wells and the Nexen well at the 200/b-A90-O-8/00 location. Figure 6 shows a 50m dolomitized reservoir with an average porosity of 18% and a length of 10 km and width of 5 km. The deliverability was calculated at three bottomhole flowing pressures, 3750, 2500 and 1000 kPaA. The initial reservoir pressure was set at 5000 kPaA, the reservoir temperature at 30° C and the wellbore radius at 0.187m (wellbore diameter = 14.875 inches). At the lowest flowing pressure (1 000 kPaA) the reservoir is capable of producing water at an initial rate of near 21,000 m^3/d that declined to 11,000 m^3/d in 2 months (Figure 7, Table 3). Over the two month period the cumulative production was about 843,000 m^3 water. At the highest flowing pressure (3750 kPaA) the initial rate was near 7,000 m^3/d that declined to about 3 700 m^3/d in 2 months of production. Over this 2-month period the well would have produced about 290,000 m^3 of water.

The model for the low deliverability case is patterned after the bulk of the drillstem test analyses and logs, and shows a reservoir with three productive zones of thicknesses of 5m, 10m and 20m over a formation thickness of 120m. The intervening carbonate was given virtually no permeability. The assigned permeabilities to these layers are respectively, 10, 5, and 1 mD (Figure 8). The well was assigned a wellbore radius of 0.187m, an initial pressure of 5,000 kPaA and produced at bottomhole flowing pressures of 3,750, 2,500 and 1,000 kPaA. The results are disappointing. At a 1,000 kPa bottomhole flowing pressure, the initial flow rate was only 55 m^3/d and declined to 41 m^3/d after 2 months of production (Figure 9, Table 4). Over this 2-month flow period only 2,648 m^3 of water were produced.

The third case that was run depicted a long narrow reservoir which was based on the analysis of the injection tests for the Nexen 200/ b-A90-J 94-O-8/00 and Apache a-2-J/94-O-9 wells. The pressure transient analysis of these tests showed anomalies in the fall-off period that could be explained using a “channel” model. A reservoir with a 50m productive thickness and a permeability of 1,400 mD was limited to a length of 10 km and a width of only 1 km (Figure 10). As in the other cases, the wellbore radius was 0.187m and the well was produced at bottomhole flowing pressures of 1,000, 2,500 and 3,750 kPaA. The highest flow rates, as is the case for the other two models, occurred at a bottomhole flowing pressure of 1,000 kPaA. At this flowing pressure the well had an initial rate near 18,000 m^3/d that declined to about 2,000 m^3/d at the end of 2-months of production (Figure 11, Table 5). Over this producing period a total of nearly 315,000 m^3 water were produced.

Q20 estimates for wells 200/d-090-G/094-O-08/00, 200/c-067-K/094-O-08/00, and 200/a-077-K/094-O-08/00 range from 20,000 m^3/day to over 150,000 m^3/day. These rates are considerably higher than any of the estimates above but since this method considers the aquifer (reservoir) to be areally infinite, it can be assumed that these rates are highly unlikely to be maintained over the long-term.

4.9.2 Deliverability Discussion

Estimates for per well frac volumes range from 8,000 m^3 to 16,000 m^3 (50,000 to 100,000 barrels of water).

Under the worst-case scenario (scenario number two above), it would be difficult to achieve the volumes of water needed for a single frac in a reasonable time frame. However, if scenarios one and three prove to be more correct, then a single water source well could possibly produce enough water for 15 to 50 fracs (at 16,000 m^3 per frac, 290,000 to 843,000 m^3 cumulative water) over a two month period. This suggests that the enhanced reservoir in the Debolt-Rundle Group could provide sufficient pumping rates to supply a winter completion program.

It should be noted however, that the rate at which a single well will provide water could be greatly affected by production from other water supply wells nearby. Without more detailed numeric modelling of possible development scenarios, it is difficult to estimate how water production in single wells will be impacted by a multi-well production program.

4.10 INJECTIVITY DISCUSSION

4.10.1 Injection Rates

An estimate of the injection rates into the high-permeability Debolt-Rundle reservoir was done in order to estimate the potential of this aquifer for water disposal. The frac gradient for the reservoir is approximately 17 kPa/m. Therefore at 500m, the reservoir would be fractured at about 8,500 kPa. The allowable limit for injection is about 80% of the fracture pressure or around 6,800 kPa.

Given that the reservoir pressure is 5,000 kPaA, the permeability is 1,400 mD, the reservoir temperature is 28°C, the wellbore radius and volume are respectively 0.187m and 55m^3, the reservoir thickness is 50m and the length and width of the reservoir are 10000m and 5000m respectively, then an injection rate forecast can be calculated for a well in the centre of this reservoir. The maximum injection pressure would have to be no more than 6800 kPa which is 1800 kPa above the initial reservoir pressure. Using this information a rate forecast was determined for a theoretical injection well using the Fekete WellTest design program. Initially the well would have an injection rate of 13,500 m^3/d that would slowly decline to 5,348 m^3/d in two months, to 1,074 m^3/d in six months and to 97 m^3/d in 12 months. This rate decline would occur at a constant sandface injection pressure of 6800 kPaA. Over this period, a total of 799,000 m^3 of water would have been injected. Of course, larger volumes could be injected if the high quality reservoir were actually larger than the 10 000m x 5000m x 50m used to model the injection.

4.10.2 Groundwater Flow Velocity

One concern of operators is the possible contamination of source water wells caused by nearby injection into the same reservoir. Determining if this will occur is very difficult without the use of numeric modelling and a good understanding of the development layout of the water source and injection wells. Once again however, some ballpark estimates can be made using simple assumptions.

Darcy's law for steady-state groundwater flow states the following:

$Q = KIA$

Where:

Q = groundwater flow rate (m^3/d)

A = Area (m^2)

K = hydraulic conductivity (m/d)

I = change in hydraulic head over a distance (m/m)

From this, average linear velocity of groundwater in an aquifer can be estimated using:

$v = Q/Af$

Where,

Q = groundwater flow (m^3/d)

f = average aquifer porosity

A = area (m^2)

For arguments sake, assume an injection well is injecting water at a pressure of 10,000 kPa into a reservoir with a midpoint elevation of –100 mASL. Once again, this corresponds to a hydraulic head of 900 mASL assuming a pressure gradient equal to 10 kPa/m.

Now, assume a water source well is located 10 km (10,000 m) away and has a hydraulic head of 460 mASL. Between the injection well and source well is a reservoir (or aquifer) with an average horizontal permeability of 1,000 mD (hydraulic conductivity = 0.78 m/d) and an average porosity of 6 %.

Assuming steady-state is reached during injection, the groundwater flow across an area of 1 m^2 would be:

Q = (0.78 m/d) x 1 m^2 x ((900 mASL – 460 mASL)/10,000 m) = 3.43 x 10^{-2} m^3/d

and the groundwater flow velocity would be:

v = 3.43 x 10^{-2} m/d/0.06/1 m^2 = 0.572 m/d

The length of time (at steady-state injection rates) for a molecule of water to cross 10 km (10,000 m) would therefore be 10,000 m/0.572 m/d = 17,482.5 days or roughly 48 years.

This estimate is provided only to give an idea of the likelihood of source well contamination given some major assumptions. Factors such as multiple injection and multiple source wells in a location, higher permeability, etc could change the above estimate dramatically and as such more detailed work predicting the likelihood of contamination would need to be completed.

5.0 SUMMARY

Formation pressure, water chemistry and permeability were studied and mapped in the Horn River Basin for Mississippian and Cretaceous aquifers. The Mississippian aquifers identified in this study include the various carbonate formations of the Rundle Group and the Mattson Formation on the western edge of the study area. In the Cretaceous, the aquifers studied included the sandstones of the Bluesky and Gething formations.

Formation pressure and water chemistry of the Debolt-Rundle and basal Cretaceous sandstone aquifers are very similar. This suggests that these aquifers can be considered one hydrostratigraphic unit and no significant aquitard, or shale unit, exists between them.

Formation water in the above aquifers is non-potable and has a TDS concentration in excess of 10,000 mg/l. In addition, measurable concentrations of H_2S have been observed in all the Mississippian and Cretaceous aquifers in the study area.

DST and pumping/injection test analyses confirmed that the highest permeabilities are found in a dolomitized zone of the Debolt-Rundle Group, also called the enhanced reservoir. Permeabilities over 30,000 mD have been identified in this zone.

Permeabilities as high as 500 mD have been measured in the basal Cretaceous sandstones. However, only DST data was analyzed for Cretaceous permeability since no pumping/injection tests were conducted in these aquifers.

No permeabilities were determined for the Mattson Formation. A pumping test conducted in the Mattson failed to produce a measurable production rate due to gas production causing pump failure. DST recoveries from the Mattson Formation further corroborate the presence of natural gas.

Deliverability estimates suggest that aquifers in the Debolt-Rundle Group can be capable of supplying the high water volumes required for shale gas well completions in the Horn River Basin. This conclusion however is highly dependent on aquifer permeability being in excess of 1,000 mD. As well, production well spacing will have a great impact on the long-term deliverability of these wells.

Estimates of injection rates were calculated for a well completed in the Debolt-Rundle Group enhanced reservoir. Initial rates were approximately 13,500 m^3/d but declined to approximately 97 m^3/d after one year of constant injection at a constant pressure.

6.0 RECOMMENDATIONS

The enhanced reservoir of the Debolt-Rundle Group in the Horn River Basin has been identified as a potential source of water for shale gas well completions and a disposal zone for produced water. Ballpark calculations of deliverability and injection initially confirm this finding, however if development of this unit as a water source progresses, some issues likely need to be addressed.

First, more good-quality permeability data is needed to determine a more accurate model of the reservoir distribution. Good-quality data refers to data obtained from pumping and injection tests. The larger radius of investigation provided by these types of tests, provides an average reservoir permeability value across a greater area, which in turn leads to more accurate deliverability and injectivity forecasting.

Second, as stated earlier, H_2S gas may exist at source/disposal zones in the Debolt-Rundle Group at concentrations exceeding certain safety limits. Two possible sources for this gas are: 1) generation in deeper formations and migration into the Debolt-Rundle and 2) in-situ gas generation in the Debolt-Rundle due to a biochemical reaction. If the source is from deeper formations, it may be possible to identify migration routes and therefore locate source/injection wells away from these routes to minimize the H_2S concentration.

In order to determine the source of the H_2S, it is recommended that a more detailed gas geochemistry study be conducted using isotopic analysis be conducted.

Second, long-term production and injection rates will be greatly influenced by well distribution. In order to better understand how well spacing will affect production and injection rates, a numerical model should be constructed for the Debolt-Rundle group. This will allow for the testing of different well spacing scenarios to determine optimum spacing for production and injection. In addition, a numerical model will further aid in determining the possibility of communication between injection wells and source wells, which could lead to contamination of source well water.

Finally, little to no pressure, chemistry and deliverability data exist for shallow, quaternary-aged aquifers in the study area. As such, the source potential for these aquifers is unknown. Therefore, it is recommended that a field program that samples and tests these aquifers be designed and implemented.

7.0 REFERENCES

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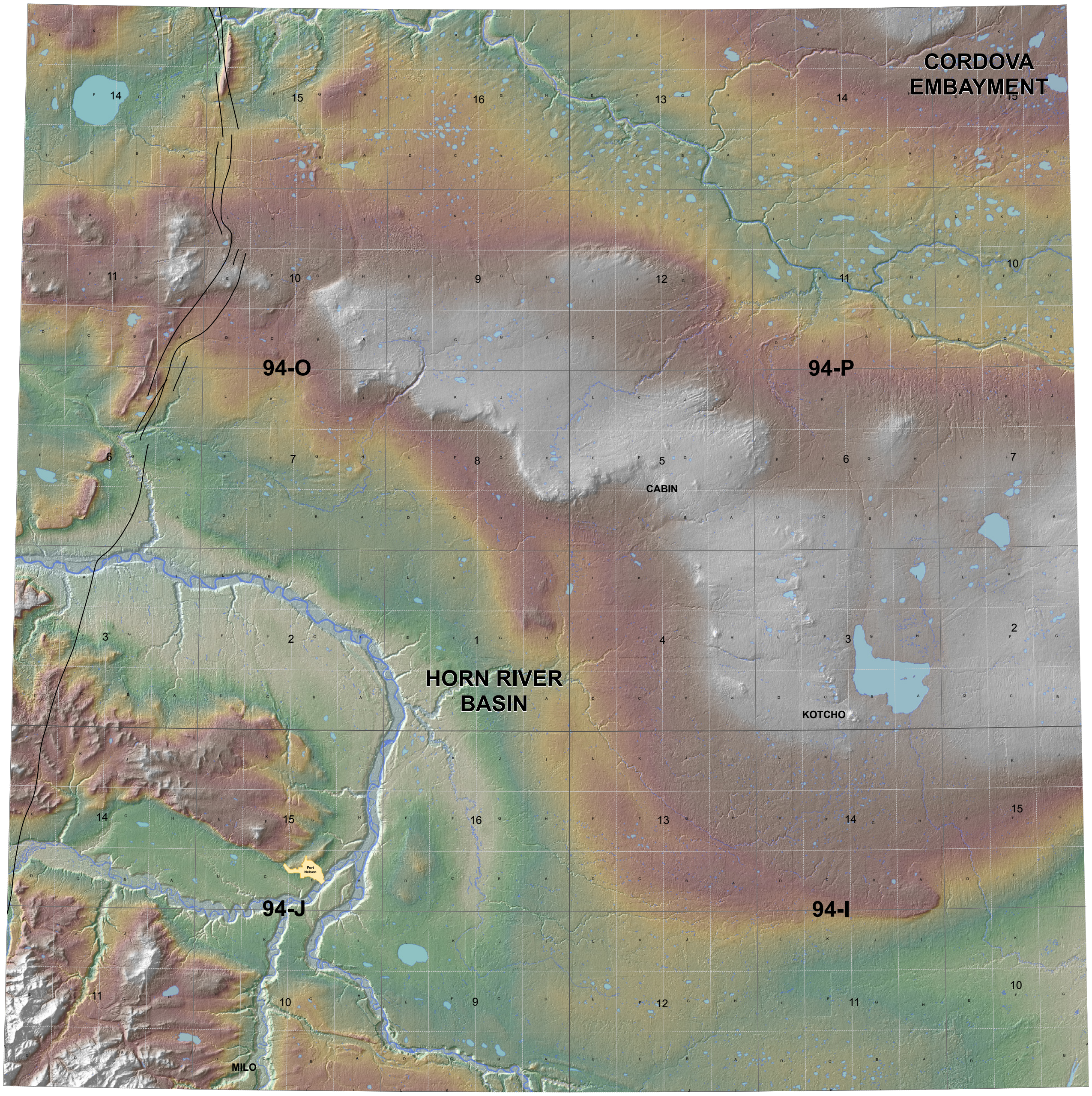

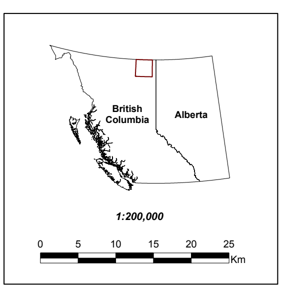

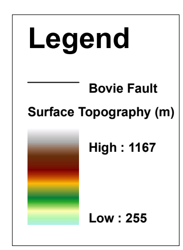

Project: GBHR

Author: G. Webb

Date: November 29, 09

Graphics: Ally Masoud

Study Area and Relief Map

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Figure 1

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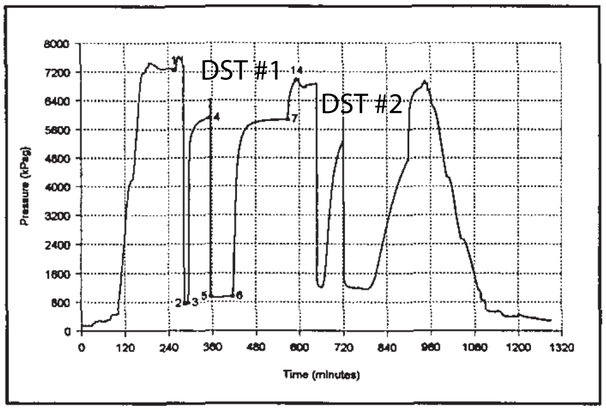
Recorder# N19

Depth: 658.00 m
Temperature: 30.1 C
Location: Outside

Recorder Type: ZI
Capacity: 41,400 kPag



		Pressure (kPag)	Time (min)
1	Initial Hydrostatic	7245	
2	Start of 1st Flow	743	
3	End of 1st Flow	772	10.5
4	End of 1st Shut-in	5895	60.5
5	Start of 2nd Flow	946	
6	End of 2nd Flow	947	60.0
7	End of 2nd Shut-in	5866	152.5
14	Final Hydrostatic	6964	

Recorder charts show that the preflow and mainflow periods and the initial and final shutins are valid. DST #1 is therefore an acceptable test of the Debolt reservoir in the d-90-K well.

Recorder Charts indicate a reservoir with fair to good permeability and with considersble damage

The recorder chart run above the shutin valve indicates that most of the flow occurred on DST #1. Flow pressures indicate that 73m of fluid were recovered. The reported recovery was 75m of gas cut mud.

Project: GBHR	Author: S.W. Burnie Sr	Recorder Charts for DST #1 and DST #2 (Debolt aquifer) d-90-K/94-O-7	Canadian Discovery Ltd.	Figure 2
Date: November 29, 09	Graphics: Ally Masoud			

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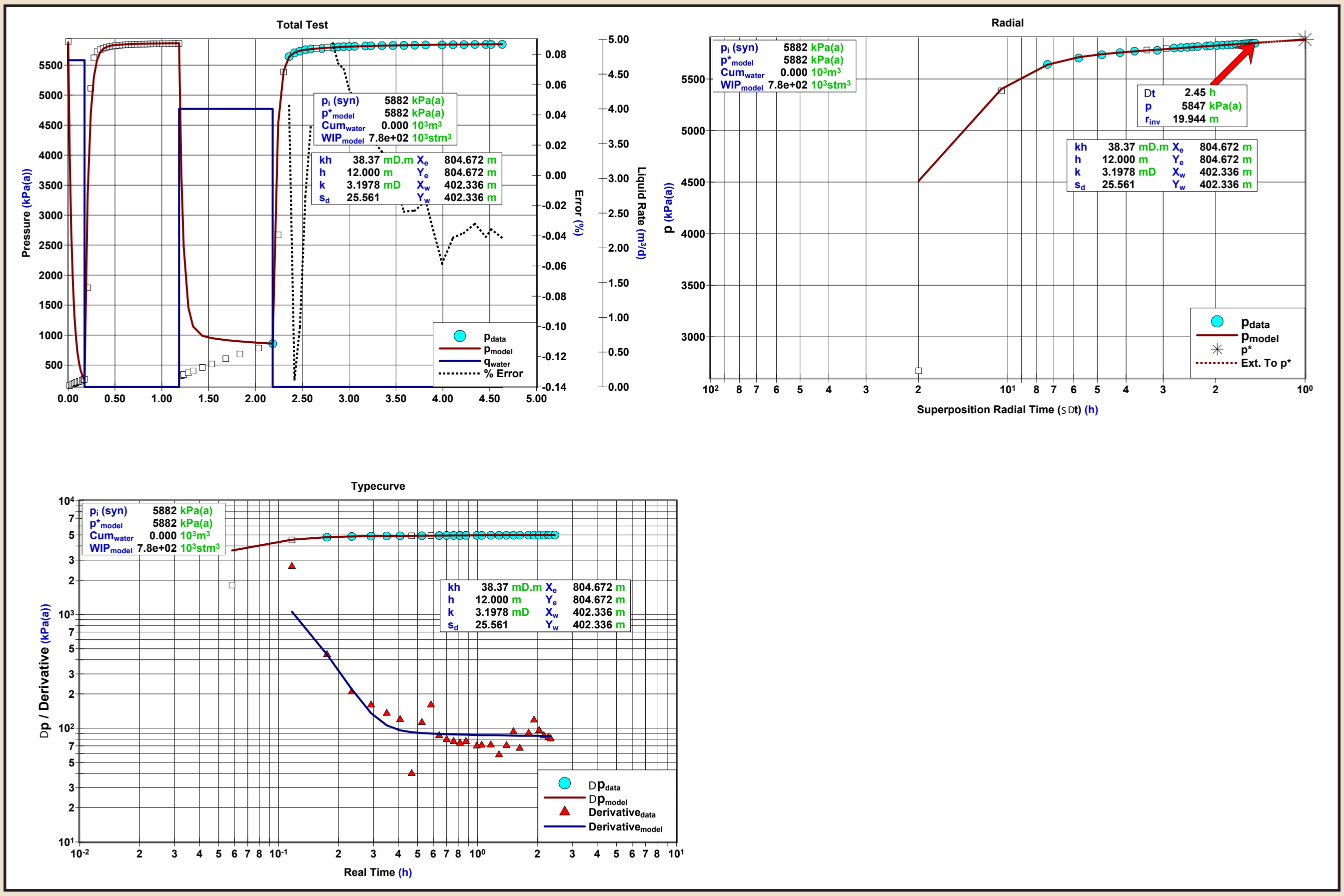

Project: GBHR	**Author:** S.W. Burnie Sr	**Radial Model Fit to DST #1 Pressure Data; d-90-K/94-O-7 Debolt Aquifer**
Date: November 29, 09	**Graphics:** Ally Masoud	

Canadian Discovery Ltd.

Figure 3

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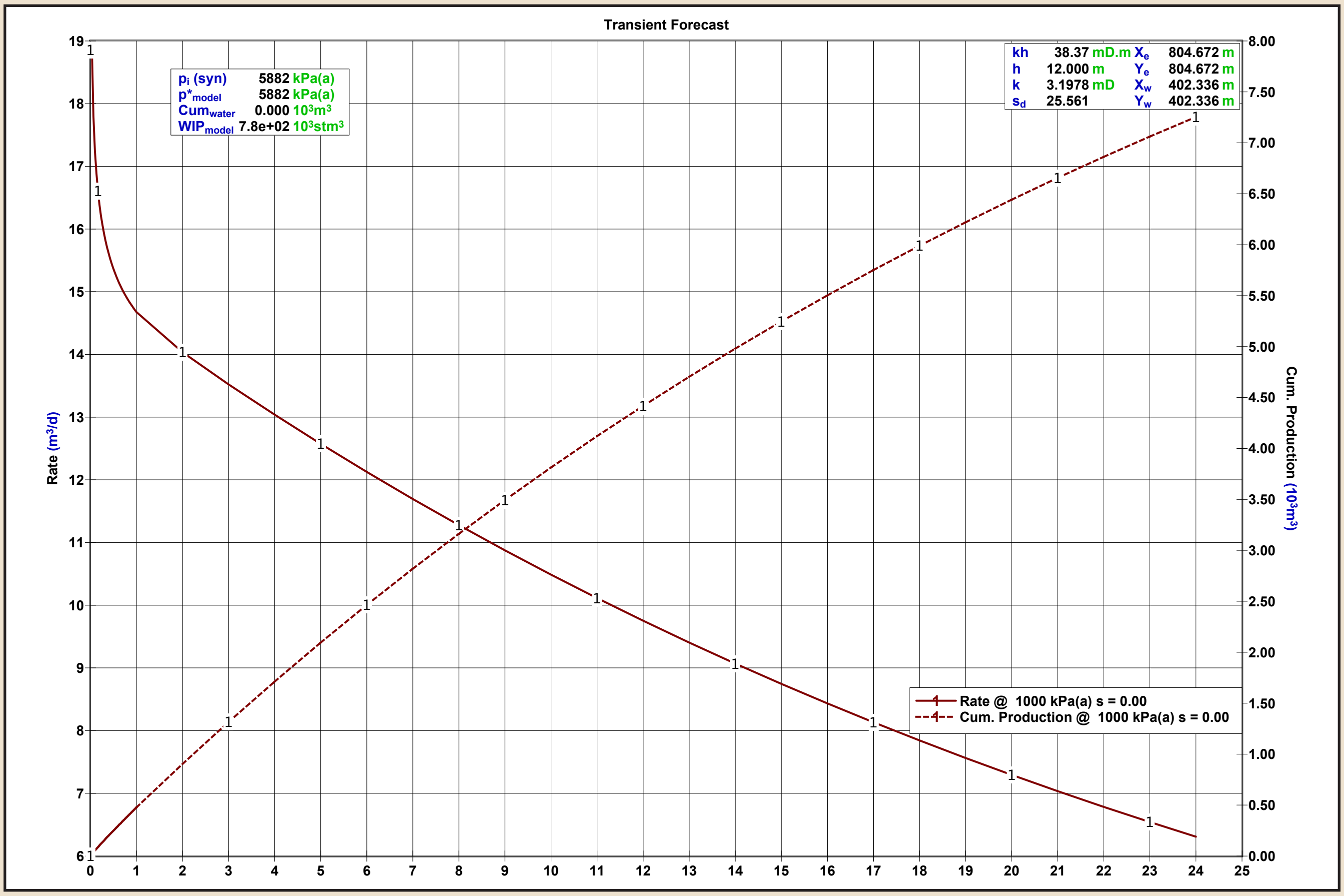

Project: GBHR

Author: S.W. Burnie Sr

Date: November 29, 09

Graphics: Ally Masoud

Rate and Cumulative Production Forecast, DST #1, d-90-K/94-O-7 Debolt Aquifer

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Figure

4

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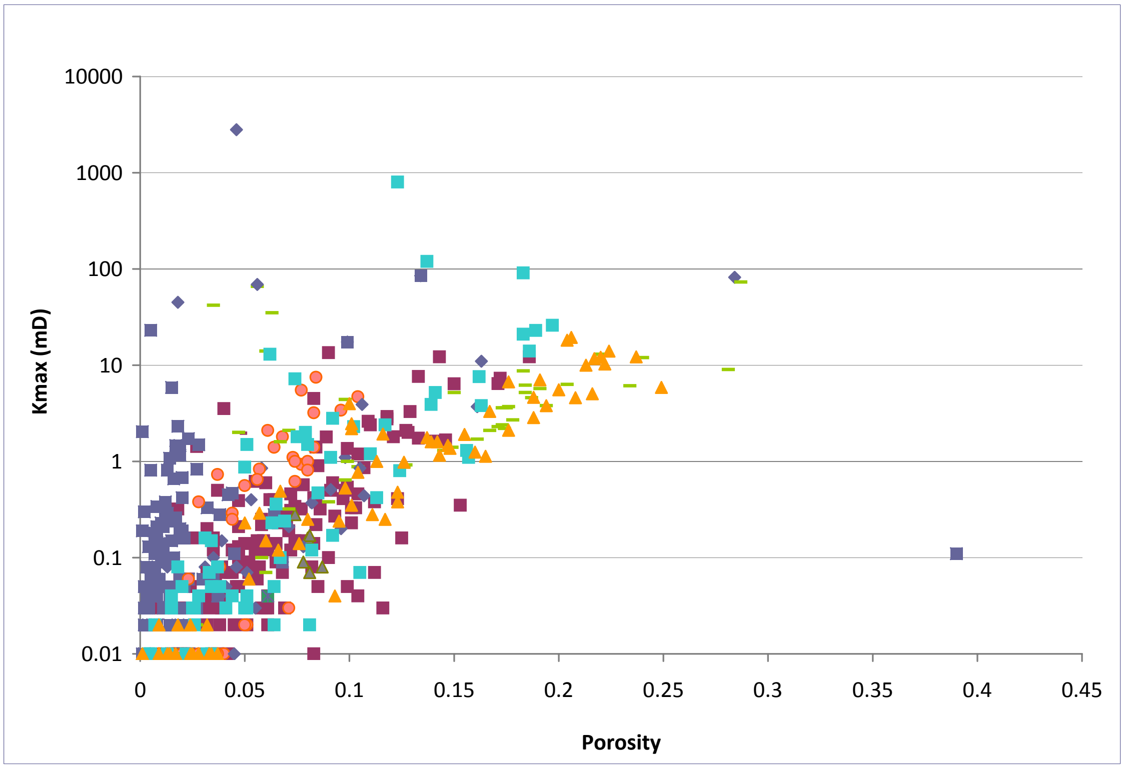

Project: GBHR	Author: S.W. Burnie Sr	Porosity-Permeability Crossplot Debolt-Rundle Core Analysis Data	Canadian Discovery Ltd.	Figure 5
Date: November 29, 09	Graphics: Ally Masoud			

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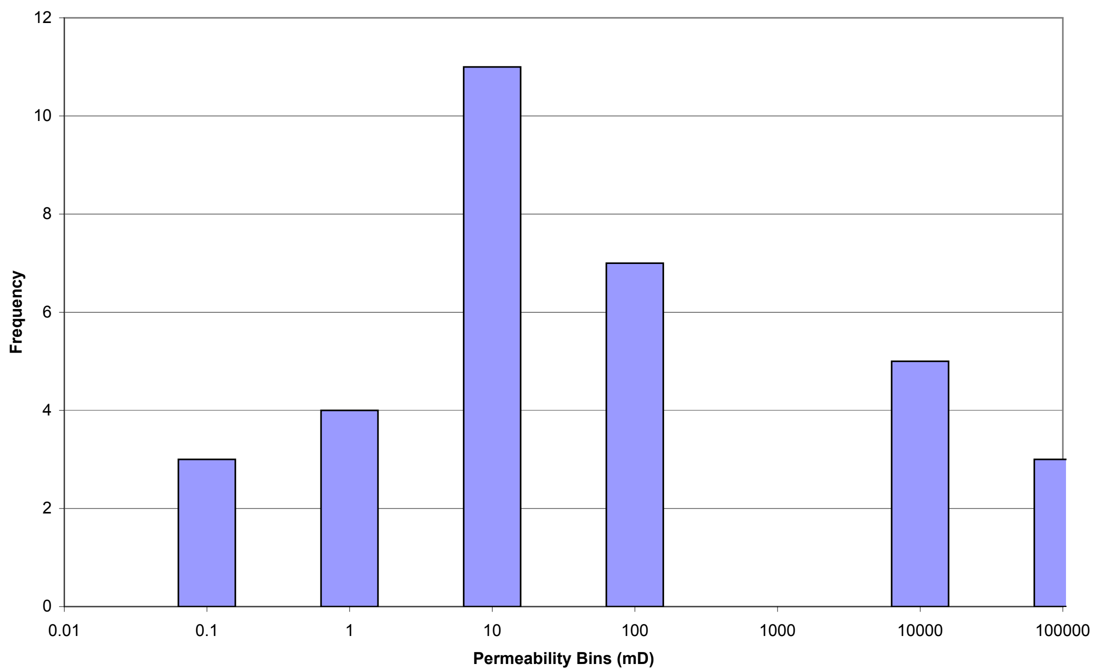

Project: GBHR	**Author:** G. Webb	**Debolt-Rundle Permeability Histogram and Normal Distribution Curve**	Figure **6a**
Date: November 29, 09	**Graphics:** Ally Masoud		

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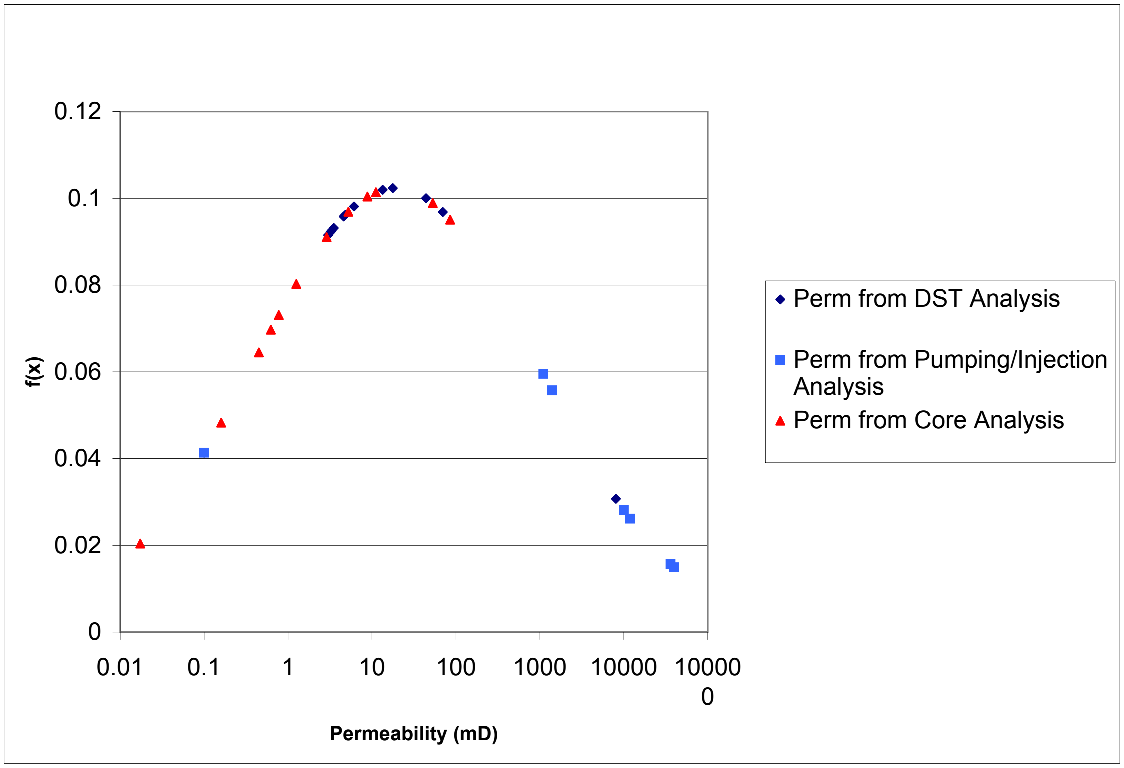

Project: GBHR	Author: G. Webb	**Debolt-Rundle Permeability Histogram and Normal Distribution Curve**	Canadian Discovery Ltd.	Figure 6b
Date: November 29, 09	Graphics: Ally Masoud			

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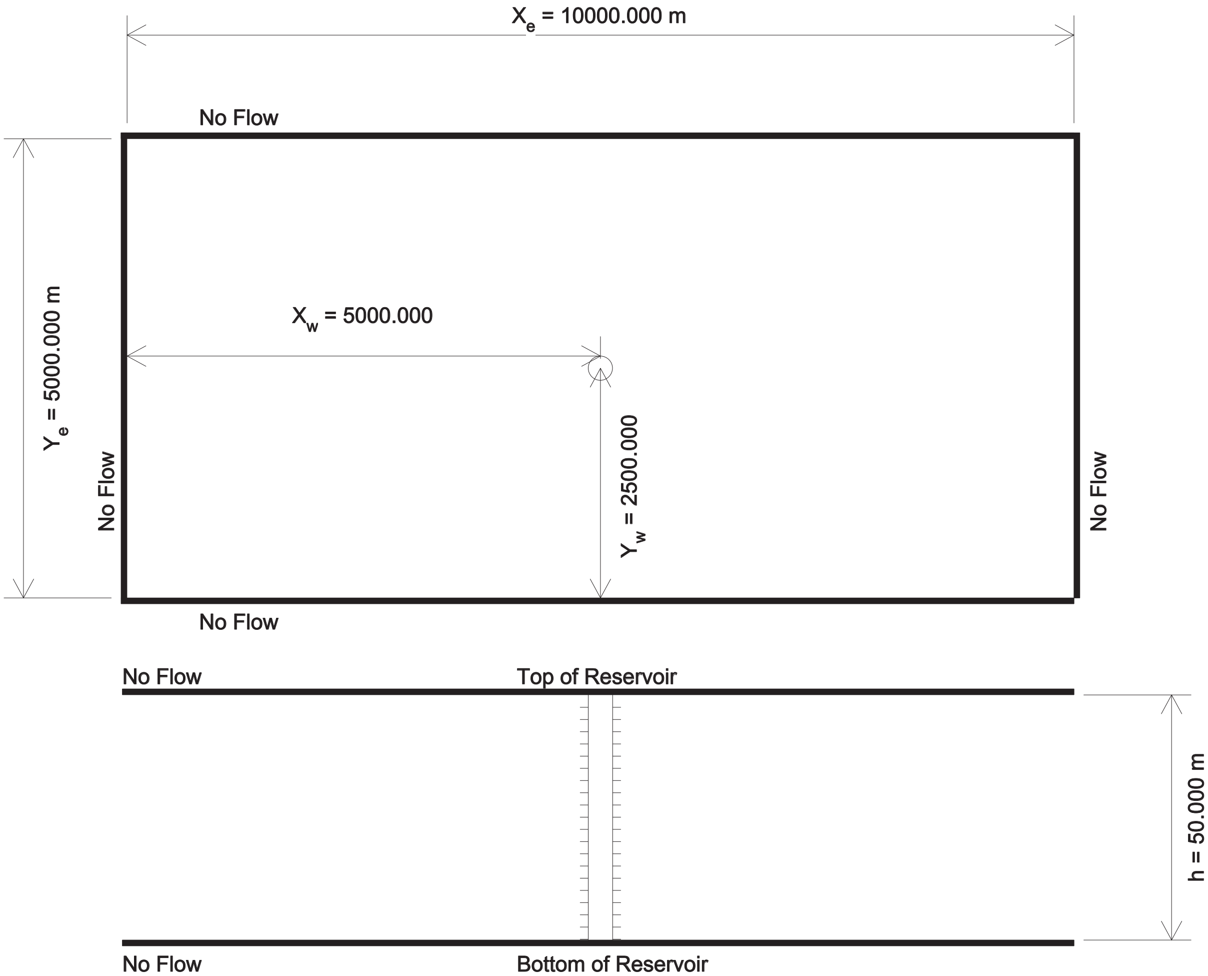
Vertical Well Model

Hi Deliverabilty Case
h = 50m; phi = 18%
Pi = 5000 kPaA; rw = 0.187m
L = 10000m; W = 5000m

k = 1400.0000 mD
s_d = 0.000
WIP_{model} = 4.5e+05 $10^3 stm^3$



Project: GBHR	**Author:** S.W. Burnie Sr	**Diagram of the High Deliverability Reservoir Model.**	Canadian Discovery Ltd.	Figure 7
Date: November 29, 09	**Graphics:** Ally Masoud			

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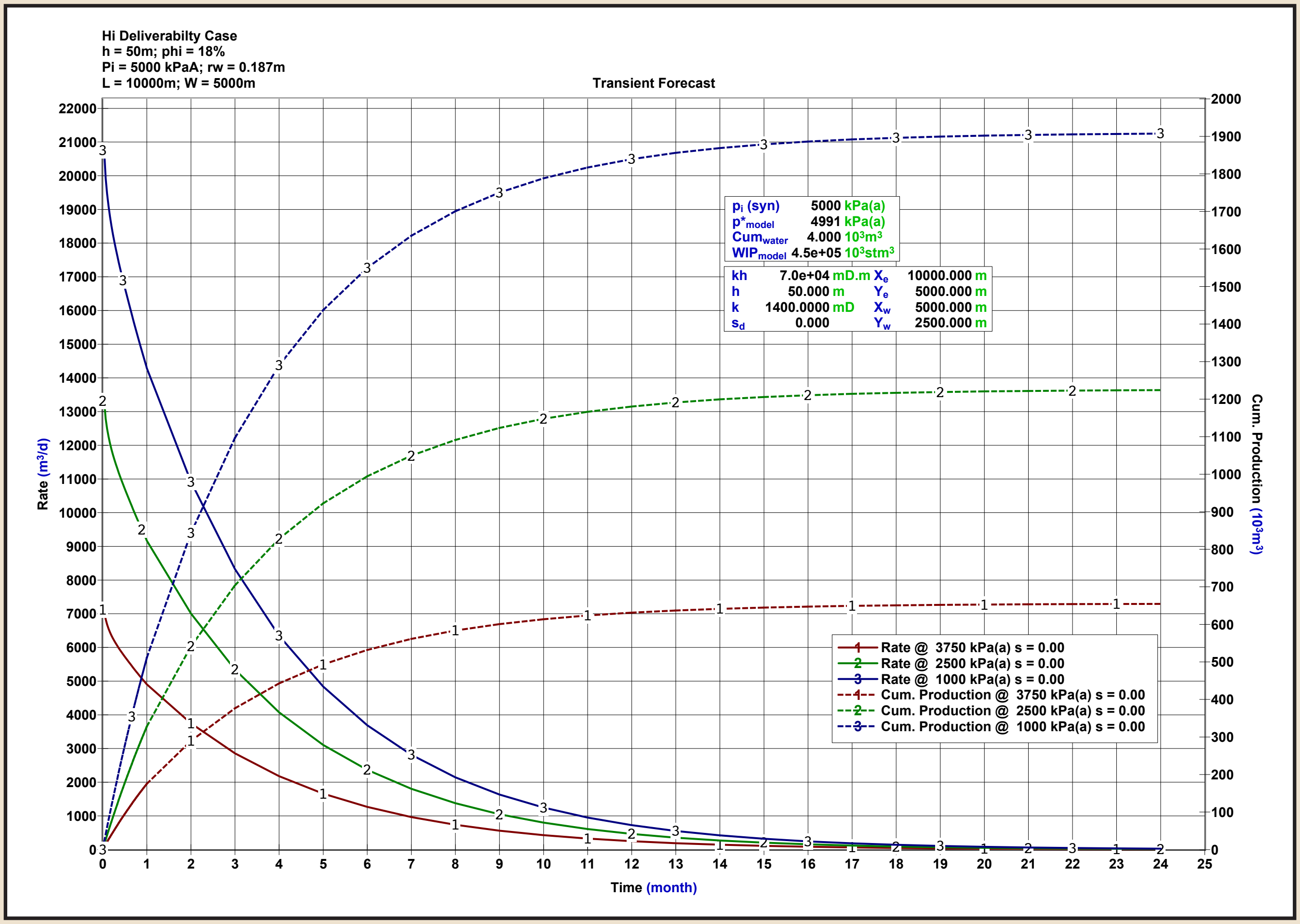

Project: GBHR	**Author:** S.W. Burnie Sr	**High Deliverability Case**	Figure 8
Date: November 29, 09	**Graphics:** Ally Masoud		

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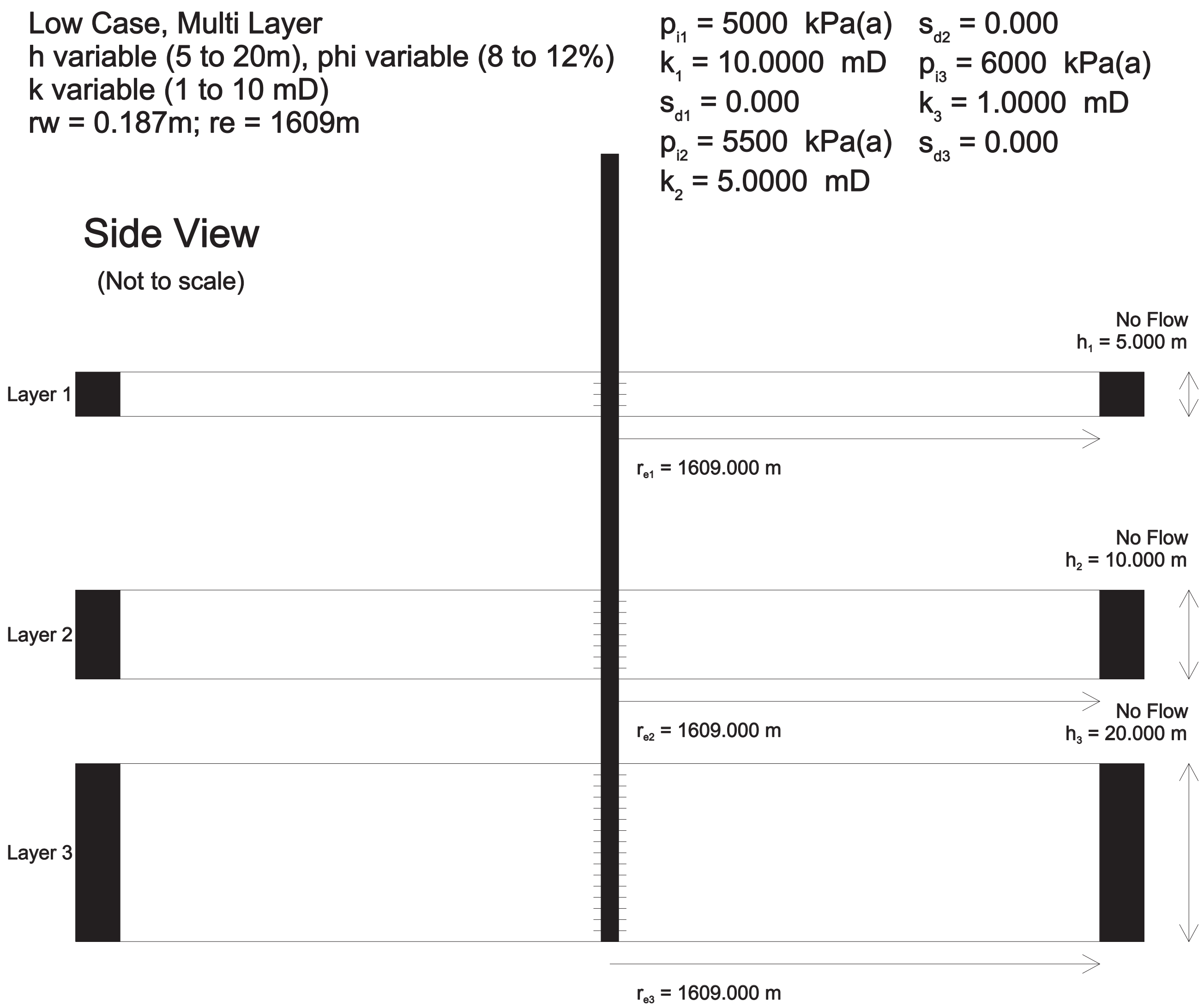
Vertical Well, Multi-Layer Reservoir Model



Project: GBHR	**Author:** S.W. Burnie Sr	**Multi-Layer Reservoir Model**	Canadian Discovery Ltd.	Figure
Date: November 29, 09	**Graphics:** Ally Masoud			9

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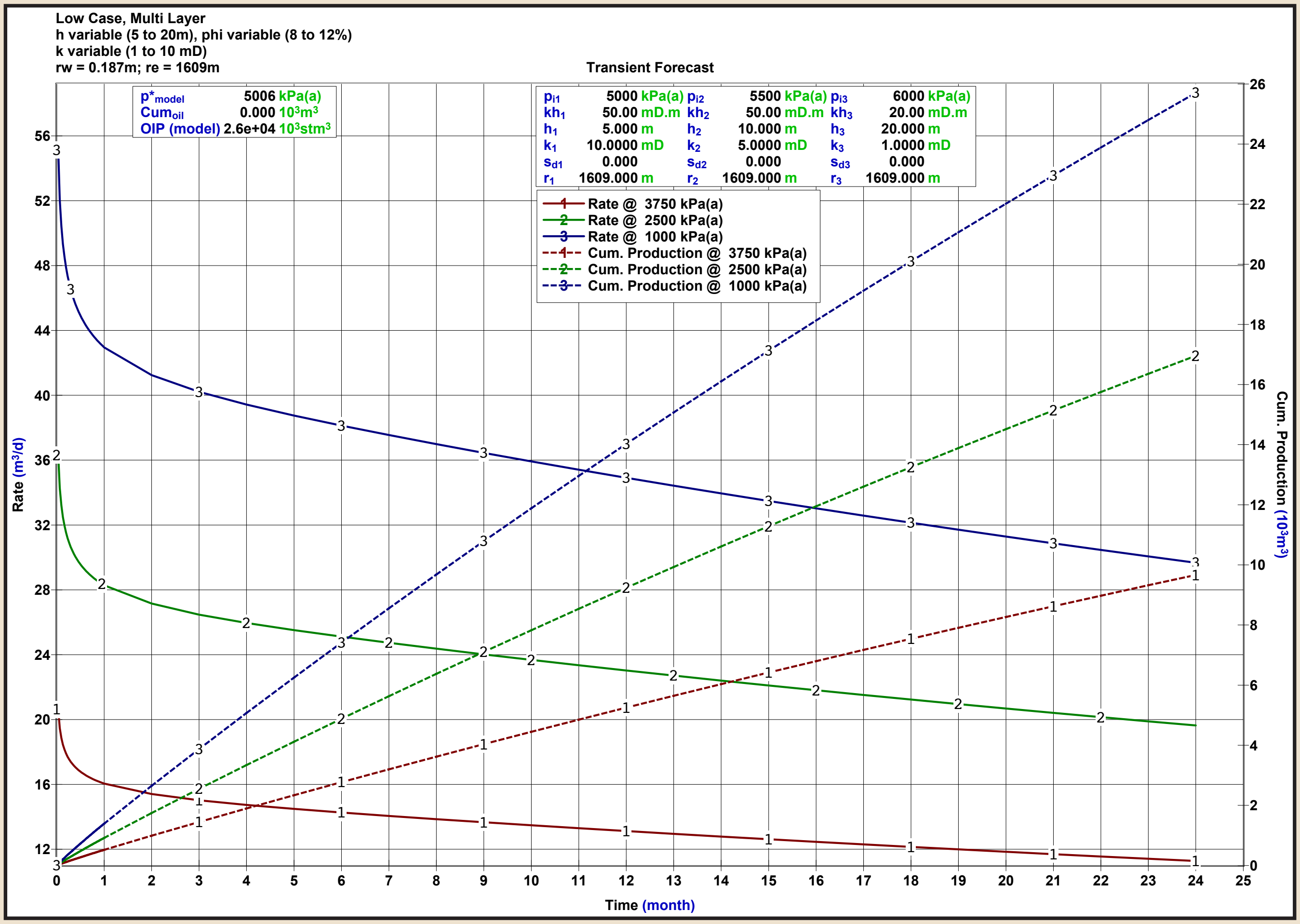

Project: GBHR	**Author:** S.W. Burnie Sr	**High Deliverability Case Rate Forecaste and Cumulative Production**	Figure 10
Date: November 29, 09	**Graphics:** Ally Masoud		

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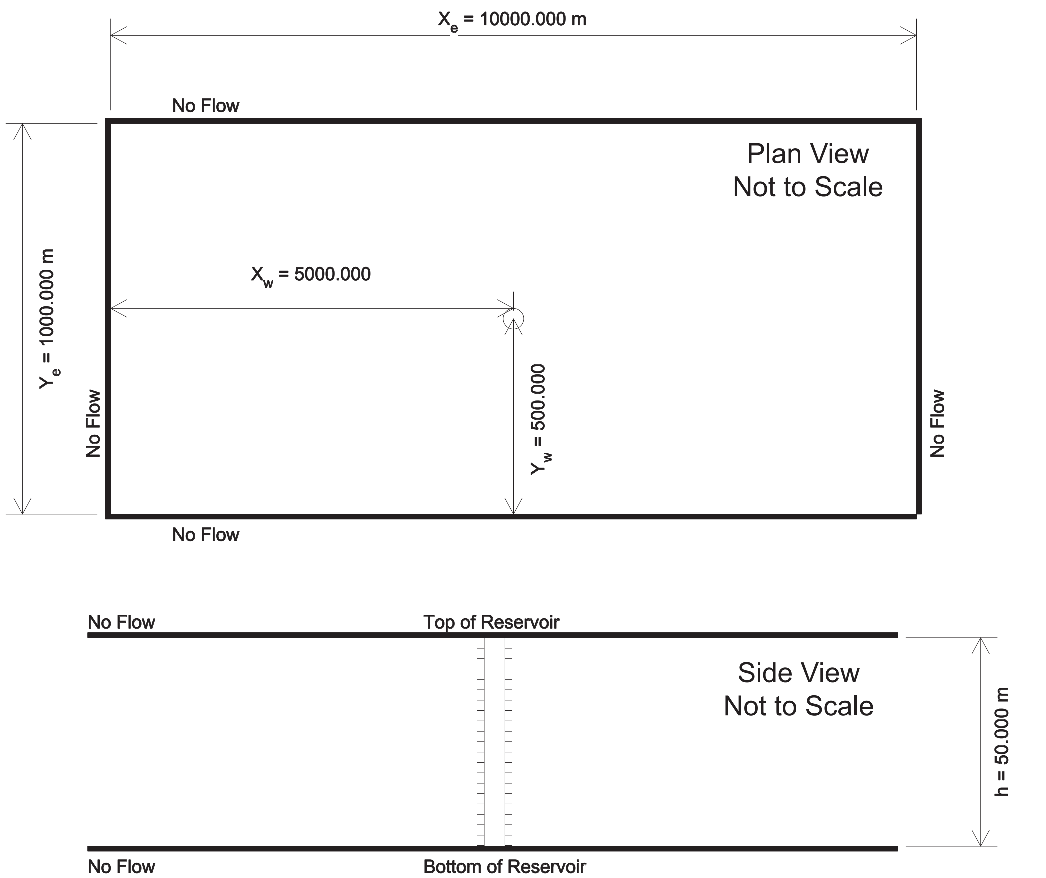
Vertical Well Reservoir Model; Long Narrow Channel

Narrow Channel Case
Pi = 5000 kPa; h= 50m
phi = 18%; rw = 0.187m
L = 10000m; W = 1000m

k = 1400.0000 mD
s_d = 0.000
WIP_{model} = 9.0e+04 $10^3 stm^3$



Project: GBHR	**Author:** S.W. Burnie Sr	**Channel Reservoir Model**	Figure 11
Date: November 29, 09	**Graphics:** Ally Masoud		

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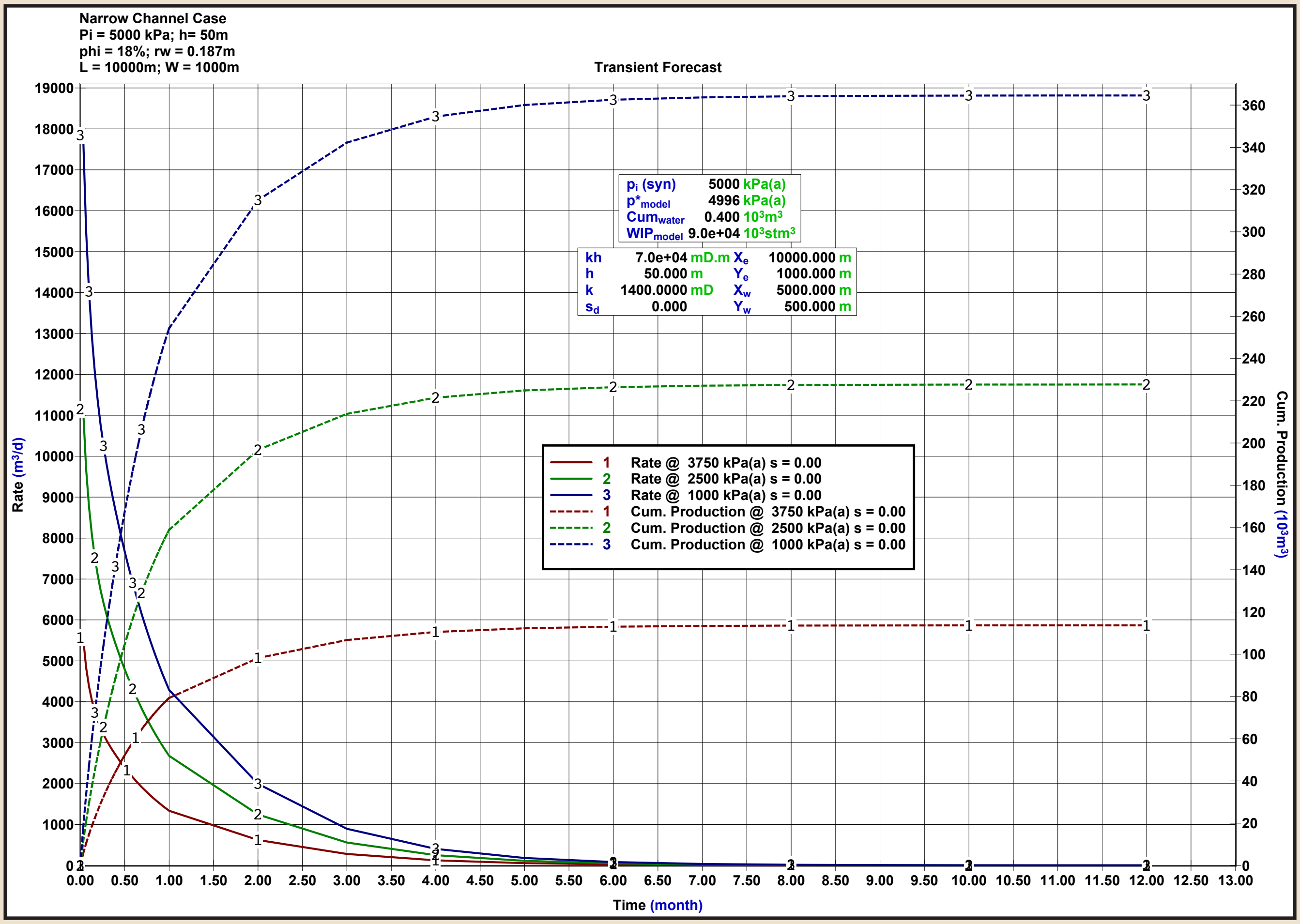

Project: GBHR	**Author:** S.W. Burnie Sr	**Vertical Well, Narrow Channel Model; Flow Rate and Cumulative Production**	Figure 12
Date: November 29, 09	**Graphics:** Ally Masoud		

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DST Summary, DST #1, Debolt Reservoir, d-90-K/94-O-7

DST Number	1		
Test Interval (Top, Bottom)	655 to 677	m	Test run in the middlw of the Debolt Formation
Pay	12	m	
Porosity	10	%	
Comments:			Good Perm, Strong Damage; DST #2 is Tite.
Test Date	20-Feb-01		
Recovery:	75	m	Thin gassy mud. Recov rec shows 70m, for DST #1 only
PF Time	10.5	min	
ISI Time	60.5	min	
MF Time	60	min	
FSI Time	152.5	min	
Drill Collar Length	76.5	m	
DC ID	61	mm	
DC Capacity	0.003	m3/m	
Drill Pipe (OD)	114	mm	
DP Capacity	0.007	m3/m	
Recov Vol in DC=	0.22	m3	
Recov Vol in DP=	0	m3	
Total Recov Vol=	0.22	m3	
Total Flow time=	70.5	min	
Average Flow Rate (liquid)=	4.5	m3/d	
Gas Rate =	No GTS	m3/d	Mud was gas cut
RRD	650	m	
Preflow Press (IPF,FPF) =	6; 158	kPaG	From Recovery Recorder
ISI Press	5766	kPaG	
MF Press (IMF, FMF) =	158; 729	kPaG	From recov rec; rec shows recov gassed-off
FSI Press	5754	kPaG	
dP preflow	152	kPa	
Length PF Recov	15.3		
Vol of Preflow Prodn	0.045	m3	
Preflow Rate	6.1	m3/d	
dP mainflow	571	kPa	
Length MF Recovery	57.4	m	
Liquid Vol Prod on MF =	0.17	m3	
Mainflow Rate	4.03	m3/d	
Recovery Density	9.72	kPa/m	Note that the recov is gas cut
Formation Temp =	28	C	
Est Form Press =	5800	kPaG	
Salinity Press Grad =	9.95	kPa/m	Mud Grad = 10.89 kPa/m
Calculated Recovery	73.3	m	
Reported Recovery =	75	m	
Gas Rate =	No GTS	m3/d	Recov. is gas cut and gassed-out to DP during FSI

Project: GBHR	Author: S.W. Burnie Sr	TABLE 1	Canadian Discovery Ltd.
Date: November 29, 09	Graphics: Ally Masoud		

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Increments for Recorder N 19, d-90-K/94-O-7 DST #1; RRD = 658m

Cumulative Time (min)	Press (kPaG)	Water Rate (m3/d)		Cumulative Time (min)	Press (kPaG)	Water Rate (m3/d)		Cumula-tive Time (min)	Press (kPaG)	Water Rate (m3/d)
0	5800	0	Pi	44.5	5754	0		145	5610	0
1	68	6	PF	46.5	5756	0		148.5	5641	0
2	77	6		48.5	5757	0		152	5662	0
3	89	6		50.5	5759	0		155.5	5676	0
4	102	6		52.5	5760	0		159	5687	0
5	116	6		54.5	5761	0		162.5	5685	0
6	125	6		56.5	5762	0		166	5701	0
7	134	6		58.5	5763	0		169.5	5707	0
8	144	6		60.5	5763	0		173	5711	0
9	156	6		62.5	5764	0		176.5	5715	0
10	166	6		64.5	5765	0		180	5718	0
10.5	171	6		66.5	5766	0		183.5	5721	0
12.5	1697	0	ISI	68.5	5766	0	MF	190.5	5726	0
14.5	5022	0		70.5	5766	0		194	5728	0
16.5	5528	0		71	5766	0		201	5732	0
18.5	5630	0		72.5	234	4		208	5735	0
20.5	5666	0		74	250	4		215	5737	0
22.5	5689	0		77	279	4		222	5740	0
24.5	5705	0		80	309	4		229	5743	0
26.5	5716	0		86	368	4		239.5	5744	0
28.5	5725	0		92	426	4		246.5	5747	0
30.5	5732	0		101	514	4		253.5	5749	0
32.5	5737	0		110	592	4	FSI	260.5	5751	0
34.5	5741	0		122	691	4		267.5	5752	0
36.5	5745	0		131	766	4		271	5753	0
38.5	5748	0		134.5	2578	0		278	5754	0
40.5	5750	0		138	5292	0				
42.5	5753	0		141.5	5548	0				

Project: GBHR	**Author:** S.W. Burnie Sr	**TABLE 3**
Date: November 29, 09	**Graphics:** Ally Masoud	

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Hi Deliverabilty Case
h = 50m; phi = 18%
Pi = 5000 kPaA; rw = 0.187m
L = 10000m; W = 5000m

Rate and Cumulative Production; High Deliverability Case

Item	Time month	Rate @ 3750 kPa(a) s = 0.00 m^3/d	Cum. Prod. @ 3750 kPa(a) s = 0.00 10^3m^3	P_R @ 3750 kPa(a) s = 0.00 kPa(a)	P_{wf} @ 3750 kPa(a) s = 0.00 kPa(a)	Rate @ 2500 kPa(a) s = 0.00 m^3/d	Cum. Prod. @ 2500 kPa(a) s = 0.00 10^3m^3	P_R @ 2500 kPa(a) s = 0.00 kPa(a)	P_{wf} @ 2500 kPa(a) s = 0.00 kPa(a)	Rate @ 1000 kPa(a) s = 0.00 m^3/d	Cum. Prod. @ 1000 kPa(a) s = 0.00 10^3m^3	P_R @ 1000 kPa(a) s = 0.00 kPa(a)	P_{wf} @ 1000 kPa(a) s = 0.00 kPa(a)
1	0.000	7123.574	0.000	5187.00	5187.00	13320.141	0.000	5187.00	5187.00	20756.021	0.000	5187.00	5187.00
2	0.033	7123.574	7.124	5171.39	3750.00	13320.141	13.320	5157.80	2500.00	20756.021	20.756	5141.50	1000.00
3	0.066	6842.369	13.966	5156.39	3750.00	12794.325	26.114	5129.76	2500.00	19936.672	40.693	5097.80	1000.00
4	0.099	6679.919	20.646	5141.74	3750.00	12490.566	38.605	5102.38	2500.00	19463.342	60.156	5055.14	1000.00
5	0.131	6553.806	27.200	5127.38	3750.00	12254.751	50.860	5075.52	2500.00	19095.885	79.252	5013.28	1000.00
6	0.164	6446.550	33.646	5113.25	3750.00	12054.195	62.914	5049.09	2500.00	18783.370	98.035	4972.11	1000.00
7	0.197	6352.291	39.999	5099.32	3750.00	11877.945	74.792	5023.06	2500.00	18508.729	116.544	4931.54	1000.00
8	0.230	6267.681	46.266	5085.59	3750.00	11719.735	86.512	4997.37	2500.00	18262.200	134.806	4891.51	1000.00
9	0.263	6190.192	52.456	5072.02	3750.00	11574.841	98.086	4972.00	2500.00	18036.420	152.843	4851.97	1000.00
10	0.296	6117.968	58.574	5058.61	3750.00	11439.791	109.526	4946.92	2500.00	17825.978	170.669	4812.90	1000.00
11	0.329	6049.628	64.624	5045.35	3750.00	11312.004	120.838	4922.13	2500.00	17626.856	188.295	4774.26	1000.00
12	0.361	5984.057	70.608	5032.23	3750.00	11189.395	132.028	4897.60	2500.00	17435.801	205.731	4736.04	1000.00
13	0.394	5920.626	76.529	5019.25	3750.00	11070.787	143.098	4873.33	2500.00	17250.981	222.982	4698.23	1000.00
14	0.427	5858.830	82.387	5006.41	3750.00	10955.238	154.054	4849.32	2500.00	17070.927	240.053	4660.81	1000.00
15	0.460	5798.291	88.186	4993.70	3750.00	10842.038	164.896	4825.55	2500.00	16894.533	256.948	4623.78	1000.00
16	0.493	5738.798	93.925	4981.12	3750.00	10730.793	175.627	4802.03	2500.00	16721.188	273.669	4587.13	1000.00
17	0.526	5680.204	99.605	4968.67	3750.00	10621.231	186.248	4778.75	2500.00	16550.462	290.219	4550.85	1000.00
18	0.559	5622.366	105.227	4956.35	3750.00	10513.080	196.761	4755.71	2500.00	16381.938	306.601	4514.94	1000.00
19	0.591	5565.275	110.792	4944.15	3750.00	10406.329	207.167	4732.90	2500.00	16215.594	322.817	4479.40	1000.00
20	0.624	5508.815	116.301	4932.07	3750.00	10300.755	217.468	4710.32	2500.00	16051.084	338.868	4444.21	1000.00
21	0.657	5452.989	121.754	4920.12	3750.00	10196.368	227.664	4687.97	2500.00	15888.424	354.756	4409.39	1000.00
22	0.690	5397.784	127.152	4908.29	3750.00	10093.142	237.757	4665.84	2500.00	15727.572	370.484	4374.91	1000.00
23	0.723	5343.148	132.495	4896.58	3750.00	9990.981	247.748	4643.94	2500.00	15568.380	386.052	4340.79	1000.00
24	0.756	5289.085	137.784	4884.98	3750.00	9889.890	257.638	4622.27	2500.00	15410.856	401.463	4307.01	1000.00
25	0.789	5235.588	143.020	4873.51	3750.00	9789.858	267.428	4600.81	2500.00	15254.981	416.718	4273.57	1000.00
26	0.821	5182.638	148.202	4862.15	3750.00	9690.848	277.119	4579.56	2500.00	15100.699	431.819	4240.47	1000.00
27	0.854	5130.216	153.333	4850.90	3750.00	9592.825	286.712	4558.54	2500.00	14947.956	446.767	4207.70	1000.00
28	0.887	5078.329	158.411	4839.77	3750.00	9495.804	296.208	4537.72	2500.00	14796.774	461.564	4175.27	1000.00
29	0.920	5026.972	163.438	4828.75	3750.00	9399.773	305.607	4517.12	2500.00	14647.133	476.211	4143.16	1000.00
30	0.953	4976.136	168.414	4817.84	3750.00	9304.717	314.912	4496.72	2500.00	14499.014	490.710	4111.38	1000.00
31	0.986	4925.815	173.340	4807.04	3750.00	9210.623	324.123	4476.53	2500.00	14352.392	505.062	4079.92	1000.00
32	1.000	4903.246	175.485	4802.34	3750.00	9168.422	328.134	4467.74	2500.00	14286.633	511.313	4066.22	1000.00
33	2.000	3746.939	289.533	4552.35	3750.00	7006.281	541.388	4000.30	2500.00	10917.491	843.614	3337.83	1000.00
34	3.000	2856.794	376.486	4361.75	3750.00	5341.826	703.979	3643.90	2500.00	8323.866	1096.971	2782.48	1000.00
35	4.000	2178.103	442.782	4216.44	3750.00	4072.765	827.944	3372.17	2500.00	6346.359	1290.139	2359.06	1000.00
36	5.000	1660.664	493.329	4105.64	3750.00	3105.222	922.459	3165.00	2500.00	4838.691	1437.416	2036.23	1000.00
37	6.000	1266.135	531.867	4021.17	3750.00	2367.505	994.520	3007.04	2500.00	3689.150	1549.705	1790.10	1000.00
38	7.000	965.360	561.250	3956.76	3750.00	1805.095	1049.463	2886.61	2500.00	2812.777	1635.319	1602.44	1000.00
39	8.000	736.011	583.652	3907.65	3750.00	1376.244	1091.352	2794.79	2500.00	2144.523	1700.593	1459.36	1000.00
40	9.000	561.155	600.732	3870.22	3750.00	1049.286	1123.290	2724.79	2500.00	1635.042	1750.359	1350.27	1000.00
41	10.000	427.837	613.755	3841.67	3750.00	799.998	1147.640	2671.41	2500.00	1246.591	1788.302	1267.10	1000.00
42	11.000	326.191	623.683	3819.91	3750.00	609.934	1166.205	2630.72	2500.00	950.426	1817.231	1203.69	1000.00
43	12.000	248.706	631.253	3803.31	3750.00	465.046	1180.360	2599.69	2500.00	724.656	1839.288	1155.34	1000.00
44	13.000	189.627	637.025	3790.66	3750.00	354.578	1191.152	2576.03	2500.00	552.519	1856.105	1118.48	1000.00
45	14.000	144.578	641.425	3781.02	3750.00	270.341	1199.381	2558.00	2500.00	421.258	1868.927	1090.38	1000.00
46	15.000	110.229	644.780	3773.66	3750.00	206.114	1205.654	2544.25	2500.00	321.175	1878.703	1068.95	1000.00
47	16.000	84.036	647.338	3768.06	3750.00	157.137	1210.437	2533.76	2500.00	244.858	1886.156	1052.61	1000.00
48	17.000	64.069	649.288	3763.78	3750.00	119.801	1214.084	2525.77	2500.00	186.678	1891.838	1040.16	1000.00
49	18.000	48.854	650.775	3760.52	3750.00	91.351	1216.864	2519.68	2500.00	142.347	1896.170	1030.66	1000.00
50	19.000	37.259	651.910	3758.04	3750.00	69.670	1218.985	2515.03	2500.00	108.562	1899.475	1023.42	1000.00
51	20.000	28.416	652.774	3756.14	3750.00	53.134	1220.602	2511.48	2500.00	82.795	1901.995	1017.89	1000.00
52	21.000	21.661	653.434	3754.70	3750.00	40.503	1221.835	2508.78	2500.00	63.114	1903.916	1013.68	1000.00
53	22.000	16.505	653.936	3753.59	3750.00	30.863	1222.774	2506.72	2500.00	48.091	1905.380	1010.47	1000.00
54	23.000	12.575	654.319	3752.76	3750.00	23.514	1223.490	2505.15	2500.00	36.641	1906.495	1008.03	1000.00
55	24.000	9.583	654.611	3752.12	3750.00	17.920	1224.035	2503.96	2500.00	27.923	1907.345	1006.16	1000.00

TABLE 3

Project: GBHR	**Author:** S.W. Burnie Sr	TABLE 3
Date: November 29, 09	**Graphics:** Ally Masoud	

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Low Case, Multi Layer
h variable (5 to 20m), phi variable (8 to 12%)
k variable (1 to 10 mD)
rw = 0.187m; re = 1609m

Rate and Cumulative Production; Low Deliverability Case

Item	Time month	Rate @ 3750 kPa(a m^3/d	Cum. Prod. @ 3750 kPa(a $10^3 m^3$	P_R @ 3750 kPa(a kPa(a)	P_{wf} @ 3750 kPa(a kPa(a)	Rate @ 2500 kPa(a m^3/d	Cum. Prod. @ 2500 kPa(a $10^3 m^3$	P_R @ 2500 kPa(a kPa(a)	P_{wf} @ 2500 kPa(a kPa(a)	Rate @ 1000 kPa(a m^3/d	Cum. Prod. @ 1000 kPa(a $10^3 m^3$	P_R @ 1000 kPa(a kPa(a)	P_{wf} @ 1000 kPa(a) kPa(a)
1	0.000	20.639	0.000	5020.20		36.320	0.000	5020.20		55.136	0.000	5020.20	
2	0.033	20.639	0.021	5019.49	3750.00	36.320	0.036	5018.95	2500.00	55.136	0.055	5018.30	1000.00
3	0.066	19.474	0.040	5018.82	3750.00	34.281	0.071	5017.76	2500.00	52.049	0.107	5016.50	1000.00
4	0.099	18.859	0.059	5018.17	3750.00	33.204	0.104	5016.62	2500.00	50.419	0.158	5014.76	1000.00
5	0.131	18.450	0.077	5017.53	3750.00	32.487	0.136	5015.50	2500.00	49.332	0.207	5013.06	1000.00
6	0.164	18.146	0.096	5016.90	3750.00	31.956	0.168	5014.39	2500.00	48.527	0.255	5011.38	1000.00
7	0.197	17.907	0.113	5016.28	3750.00	31.536	0.200	5013.30	2500.00	47.891	0.303	5009.72	1000.00
8	0.230	17.710	0.131	5015.67	3750.00	31.191	0.231	5012.22	2500.00	47.368	0.351	5008.09	1000.00
9	0.263	17.544	0.149	5015.07	3750.00	30.899	0.262	5011.16	2500.00	46.925	0.398	5006.47	1000.00
10	0.296	17.400	0.166	5014.46	3750.00	30.647	0.293	5010.10	2500.00	46.543	0.444	5004.86	1000.00
11	0.329	17.273	0.183	5013.87	3750.00	30.425	0.323	5009.05	2500.00	46.207	0.490	5003.26	1000.00
12	0.361	17.161	0.201	5013.28	3750.00	30.227	0.353	5008.00	2500.00	45.908	0.536	5001.68	1000.00
13	0.394	17.059	0.218	5012.69	3750.00	30.049	0.383	5006.97	2500.00	45.638	0.582	5000.10	1000.00
14	0.427	16.967	0.235	5012.10	3750.00	29.888	0.413	5005.93	2500.00	45.393	0.627	4998.53	1000.00
15	0.460	16.883	0.251	5011.52	3750.00	29.740	0.443	5004.91	2500.00	45.169	0.673	4996.97	1000.00
16	0.493	16.805	0.268	5010.94	3750.00	29.604	0.472	5003.88	2500.00	44.962	0.717	4995.42	1000.00
17	0.526	16.733	0.285	5010.36	3750.00	29.478	0.502	5002.87	2500.00	44.771	0.762	4993.87	1000.00
18	0.559	16.666	0.302	5009.78	3750.00	29.360	0.531	5001.85	2500.00	44.593	0.807	4992.33	1000.00
19	0.591	16.604	0.318	5009.21	3750.00	29.251	0.561	5000.84	2500.00	44.427	0.851	4990.80	1000.00
20	0.624	16.545	0.335	5008.64	3750.00	29.147	0.590	4999.83	2500.00	44.270	0.896	4989.27	1000.00
21	0.657	16.489	0.351	5008.07	3750.00	29.050	0.619	4998.83	2500.00	44.123	0.940	4987.75	1000.00
22	0.690	16.437	0.368	5007.50	3750.00	28.959	0.648	4997.83	2500.00	43.985	0.984	4986.23	1000.00
23	0.723	16.388	0.384	5006.93	3750.00	28.872	0.677	4996.83	2500.00	43.853	1.027	4984.71	1000.00
24	0.756	16.341	0.400	5006.37	3750.00	28.789	0.705	4995.84	2500.00	43.728	1.071	4983.20	1000.00
25	0.789	16.296	0.417	5005.81	3750.00	28.711	0.734	4994.85	2500.00	43.609	1.115	4981.69	1000.00
26	0.821	16.253	0.433	5005.25	3750.00	28.636	0.763	4993.86	2500.00	43.495	1.158	4980.19	1000.00
27	0.854	16.212	0.449	5004.69	3750.00	28.564	0.791	4992.87	2500.00	43.387	1.202	4978.69	1000.00
28	0.887	16.173	0.465	5004.13	3750.00	28.496	0.820	4991.89	2500.00	43.283	1.245	4977.20	1000.00
29	0.920	16.136	0.482	5003.57	3750.00	28.431	0.848	4990.90	2500.00	43.184	1.288	4975.71	1000.00
30	0.953	16.100	0.498	5003.01	3750.00	28.367	0.877	4989.92	2500.00	43.088	1.331	4974.22	1000.00
31	0.986	16.066	0.514	5002.46	3750.00	28.307	0.905	4988.95	2500.00	42.996	1.374	4972.73	1000.00
32	1.000	16.050	0.521	5002.22	3750.00	28.280	0.917	4988.52	2500.00	42.955	1.393	4972.08	1000.00
33	2.000	15.409	0.990	4986.01	3750.00	27.153	1.744	4959.97	2500.00	41.247	2.648	4928.72	1000.00
34	3.000	15.023	1.447	4970.22	3750.00	26.472	2.549	4932.14	2500.00	40.211	3.872	4886.44	1000.00
35	4.000	14.733	1.895	4954.73	3750.00	25.957	3.340	4904.85	2500.00	39.426	5.072	4844.99	1000.00
36	5.000	14.488	2.336	4939.50	3750.00	25.516	4.116	4878.02	2500.00	38.750	6.252	4804.25	1000.00
37	6.000	14.265	2.771	4924.50	3750.00	25.113	4.881	4851.62	2500.00	38.132	7.413	4764.15	1000.00
38	7.000	14.056	3.198	4909.72	3750.00	24.734	5.633	4825.61	2500.00	37.548	8.555	4724.68	1000.00
39	8.000	13.857	3.620	4895.15	3750.00	24.371	6.375	4799.99	2500.00	36.988	9.681	4685.79	1000.00
40	9.000	13.665	4.036	4880.79	3750.00	24.020	7.106	4774.73	2500.00	36.447	10.791	4647.47	1000.00
41	10.000	13.479	4.446	4866.61	3750.00	23.680	7.827	4749.83	2500.00	35.923	11.884	4609.70	1000.00
42	11.000	13.298	4.851	4852.63	3750.00	23.350	8.538	4725.29	2500.00	35.412	12.962	4572.47	1000.00
43	12.000	13.122	5.251	4838.84	3750.00	23.027	9.239	4701.07	2500.00	34.913	14.025	4535.76	1000.00
44	13.000	12.950	5.645	4825.22	3750.00	22.712	9.930	4677.20	2500.00	34.426	15.072	4499.56	1000.00
45	14.000	12.783	6.034	4811.78	3750.00	22.404	10.612	4653.64	2500.00	33.950	16.106	4463.87	1000.00
46	15.000	12.618	6.418	4798.51	3750.00	22.103	11.285	4630.40	2500.00	33.484	17.125	4428.67	1000.00
47	16.000	12.458	6.797	4785.42	3750.00	21.807	11.948	4607.47	2500.00	33.027	18.130	4393.94	1000.00
48	17.000	12.300	7.171	4772.48	3750.00	21.518	12.603	4584.85	2500.00	32.579	19.122	4359.69	1000.00
49	18.000	12.145	7.541	4759.71	3750.00	21.234	13.250	4562.52	2500.00	32.140	20.100	4325.90	1000.00
50	19.000	11.994	7.906	4747.10	3750.00	20.955	13.888	4540.49	2500.00	31.709	21.065	4292.56	1000.00
51	20.000	11.845	8.267	4734.65	3750.00	20.682	14.517	4518.75	2500.00	31.286	22.017	4259.66	1000.00
52	21.000	11.698	8.623	4722.35	3750.00	20.413	15.138	4497.29	2500.00	30.871	22.957	4227.21	1000.00
53	22.000	11.555	8.974	4710.20	3750.00	20.149	15.752	4476.10	2500.00	30.463	23.884	4195.18	1000.00
54	23.000	11.413	9.322	4698.20	3750.00	19.890	16.357	4455.19	2500.00	30.063	24.799	4163.57	1000.00
55	24.000	11.275	9.665	4686.35	3750.00	19.636	16.955	4434.54	2500.00	29.669	25.702	4132.38	1000.00

TABLE 4

Project: GBHR	**Author:** S.W. Burnie Sr	**TABLE 4**
Date: November 29, 09	**Graphics:** Ally Masoud	

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Narrow Channel Case
Pi = 5000 kPa; h= 50m
phi = 18%; rw = 0.187m
L = 10000m; W = 1000m

Rate and Cumulative Production, Long Channel Reservoir Model

Item	Time	Rate @ 3750 kPa(a) s = 0.00	Cum. Prod. @ 3750 kPa(a) s = 0.00	P_R @ 3750 kPa(a) s = 0.00	P_{wf} @ 3750 kPa(a) s = 0.00	Rate @ 2500 kPa(a) s = 0.00	Cum. Prod. @ 2500 kPa(a) s = 0.00	P_R @ 2500 kPa(a) s = 0.00	P_{wf} @ 2500 kPa(a) s = 0.00	Rate @ 1000 kPa(a) s = 0.00	Cum. Prod. @ 1000 kPa(a) s = 0.00	P_R @ 1000 kPa(a) s = 0.00	P_{wf} @ 1000 kPa(a) s = 0.00
	month	m^3/d	10^3m^3	kPa(a)	kPa(a)	m^3/d	10^3m^3	kPa(a)	kPa(a)	m^3/d	10^3m^3	kPa(a)	kPa(a)
1	0.000	5564.362	0.000	4996.00	4996.00	11146.587	0.000	4996.00	4996.00	17845.257	0.000	4996.00	4996.00
2	0.033	5564.362	5.564	4935.02	3750.00	11146.587	11.147	4873.84	2500.00	17845.257	17.845	4800.42	1000.00
3	0.066	4839.922	10.404	4881.97	3750.00	9695.381	20.842	4767.58	2500.00	15521.932	33.367	4630.30	1000.00
4	0.099	4372.089	14.776	4834.05	3750.00	8758.213	29.600	4671.59	2500.00	14021.563	47.389	4476.63	1000.00
5	0.131	4025.121	18.801	4789.94	3750.00	8063.164	37.663	4583.22	2500.00	12908.816	60.298	4335.15	1000.00
6	0.164	3753.830	22.555	4748.80	3750.00	7519.711	45.183	4500.80	2500.00	12038.767	72.336	4203.21	1000.00
7	0.197	3535.111	26.090	4710.05	3750.00	7081.571	52.265	4423.19	2500.00	11337.323	83.674	4078.95	1000.00
8	0.230	3353.388	29.444	4673.30	3750.00	6717.542	58.982	4349.57	2500.00	10754.526	94.428	3961.08	1000.00
9	0.263	3197.471	32.641	4638.26	3750.00	6405.207	65.387	4279.37	2500.00	10254.490	104.683	3848.70	1000.00
10	0.296	3059.584	35.701	4604.72	3750.00	6128.991	71.516	4212.19	2500.00	9812.278	114.495	3741.15	1000.00
11	0.329	2934.505	38.635	4572.56	3750.00	5878.430	77.395	4147.77	2500.00	9411.140	123.906	3638.01	1000.00
12	0.361	2818.477	41.454	4541.67	3750.00	5646.002	83.041	4085.89	2500.00	9039.032	132.945	3538.94	1000.00
13	0.394	2709.540	44.163	4511.98	3750.00	5427.779	88.469	4026.40	2500.00	8689.665	141.635	3443.71	1000.00
14	0.427	2606.241	46.770	4483.41	3750.00	5220.850	93.689	3969.18	2500.00	8358.380	149.993	3352.10	1000.00
15	0.460	2507.608	49.277	4455.93	3750.00	5023.266	98.713	3914.13	2500.00	8042.056	158.035	3263.96	1000.00
16	0.493	2413.161	51.690	4429.48	3750.00	4834.068	103.547	3861.15	2500.00	7739.157	165.774	3179.14	1000.00
17	0.526	2322.533	54.013	4404.03	3750.00	4652.523	108.199	3810.15	2500.00	7448.510	173.223	3097.51	1000.00
18	0.559	2235.322	56.248	4379.53	3750.00	4477.821	112.677	3761.08	2500.00	7168.819	180.392	3018.94	1000.00
19	0.591	2151.588	58.400	4355.95	3750.00	4310.083	116.987	3713.84	2500.00	6900.276	187.292	2943.31	1000.00
20	0.624	2070.905	60.471	4333.25	3750.00	4148.458	121.136	3668.37	2500.00	6641.522	193.934	2870.52	1000.00
21	0.657	1993.298	62.464	4311.40	3750.00	3992.995	125.129	3624.61	2500.00	6392.632	200.326	2800.46	1000.00
22	0.690	1918.668	64.383	4290.38	3750.00	3843.495	128.972	3582.49	2500.00	6153.288	206.479	2733.02	1000.00
23	0.723	1846.760	66.229	4270.14	3750.00	3699.448	132.672	3541.94	2500.00	5922.674	212.402	2668.11	1000.00
24	0.756	1777.556	68.007	4250.65	3750.00	3560.818	136.232	3502.92	2500.00	5700.732	218.103	2605.63	1000.00
25	0.789	1710.975	69.718	4231.90	3750.00	3427.443	139.660	3465.35	2500.00	5487.205	223.590	2545.49	1000.00
26	0.821	1646.891	71.365	4213.85	3750.00	3299.070	142.959	3429.19	2500.00	5281.684	228.872	2487.60	1000.00
27	0.854	1585.182	72.950	4196.48	3750.00	3175.453	146.134	3394.39	2500.00	5083.778	233.956	2431.89	1000.00
28	0.887	1525.799	74.476	4179.76	3750.00	3056.496	149.191	3360.89	2500.00	4893.333	238.849	2378.26	1000.00
29	0.920	1468.650	75.945	4163.66	3750.00	2942.015	152.133	3328.65	2500.00	4710.053	243.559	2326.64	1000.00
30	0.953	1413.643	77.358	4148.17	3750.00	2831.823	154.965	3297.61	2500.00	4533.640	248.093	2276.95	1000.00
31	0.986	1360.680	78.719	4133.25	3750.00	2725.728	157.690	3267.74	2500.00	4363.786	252.456	2229.12	1000.00
32	1.000	1336.576	79.304	4126.85	3750.00	2677.443	158.862	3254.90	2500.00	4286.484	254.332	2208.57	1000.00
33	2.000	621.316	98.215	3919.58	3750.00	1244.627	196.745	2839.71	2500.00	1992.600	314.981	1543.86	1000.00
34	3.000	279.549	106.724	3826.33	3750.00	559.995	213.790	2652.90	2500.00	896.531	342.270	1244.78	1000.00
35	4.000	125.776	110.552	3784.37	3750.00	251.955	221.459	2568.85	2500.00	403.370	354.547	1110.22	1000.00
36	5.000	56.586	112.274	3765.49	3750.00	113.353	224.909	2531.03	2500.00	181.474	360.071	1049.69	1000.00
37	6.000	25.462	113.049	3757.00	3750.00	51.006	226.462	2514.02	2500.00	81.659	362.556	1022.44	1000.00
38	7.000	11.456	113.398	3753.18	3750.00	22.949	227.160	2506.36	2500.00	36.740	363.675	1010.19	1000.00
39	8.000	5.151	113.555	3751.46	3750.00	10.319	227.474	2502.92	2500.00	16.520	364.177	1004.68	1000.00
40	9.000	2.327	113.626	3750.68	3750.00	4.661	227.616	2501.37	2500.00	7.463	364.405	1002.19	1000.00
41	10.000	1.042	113.657	3750.33	3750.00	2.087	227.680	2500.67	2500.00	3.341	364.506	1001.07	1000.00
42	11.000	0.462	113.671	3750.18	3750.00	0.926	227.708	2500.36	2500.00	1.482	364.551	1000.58	1000.00
43	12.000	0.211	113.678	3750.11	3750.00	0.422	227.721	2500.22	2500.00	0.676	364.572	1000.35	1000.00

TABLE 5

Project: GBHR	Author: S.W. Burnie Sr	TABLE 5
Date: November 29, 09	Graphics: Ally Masoud	

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