FORT ST. JOHN OIL FIELD: NORTH PINE A POOL

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ABSTRACT

The North Pine A pool in the Fort St. John oil field is one of the oldest oil discoveries in British Columbia. Like most early oil discoveries in BC, exploration was facilitated by proximity to the Alaska Highway, which was built in the 1940s to improve access to Alaska during World War II. The discovery well at 3-14-83-18W6 was drilled by Pacific Petroleum Ltd. in 1952 and was initially completed in the Baldonnel Formation, although their original drilling licence indicates they expected production to be from the Permo-Pennsylvanian.

Oil production started in 1956 and remained steady until approximately 1992, with two or more wells always producing. A steady decline began circa 2000. Water cut has averaged approximately 12% over the life of the pool; this percentage has not increased greatly over time. The estimated original oil in place is 4 231 500 barrels, of which 2 080 960 barrels have been produced as of October 2012. This represents a very efficient recovery rate of 50%, assisted by gas expansion in a permeable reservoir.

Some level of communication for the North Pine exists over the entire pool but a partial permeability barrier appears to impede communication between north and south. The North Pine is thin and discontinuous, so trapping appears to be primarily stratigraphic. Seismic shows it is truncated to the north by a fault, so structure appears to constrain the pool in that direction. The North Pine was deposited as a winnowed, narrow and linear shoreface sand trending north-northeast. Production has declined along with a decline in pool-wide pressures. A secondary recovery scheme could be effective because good permeability in the North Pine should permit good receptivity of water or gas injected to increase pressure.

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DEVELOPMENT HISTORY

The North Pine A pool in the Fort St. John Oil Field is one of the oldest oil discoveries in British Columbia (Table 1). Like most early oil discoveries in the province, exploration was facilitated by proximity to the Alaska Highway (Fig. 1), which was built in the 1940s to improve access to Alaska during World War II.

Oil and gas rights for this pool were first issued as permit 22 by the Government of British Columbia to the Peace River Natural Gas Company in 1949. Reconnaissance geological mapping was done during the summers of 1949–1950 (Falconer, 1951) to fulfill the requirements of this permit. In the course of their mapping, the Peace River Natural Gas Company identified what they believed was a promising structure. Further encouragement was provided by oil shows in the Lower Cretaceous and Upper Triassic sections from previous drilling in the area. Seismic surveys were not used because the technology was still in a rudimentary state at that time.

Discovery well 3-14-83-18W6 was drilled by Pacific Petroleum Ltd.[1] (Pacific) in 1952 and was initially completed in the Baldonnel Formation (formerly known as Triassic A in the 1950s), although

[1] The relationship of Pacific Petroleum Ltd. with the original permit holder, Peace River Natural Gas Company, is uncertain.

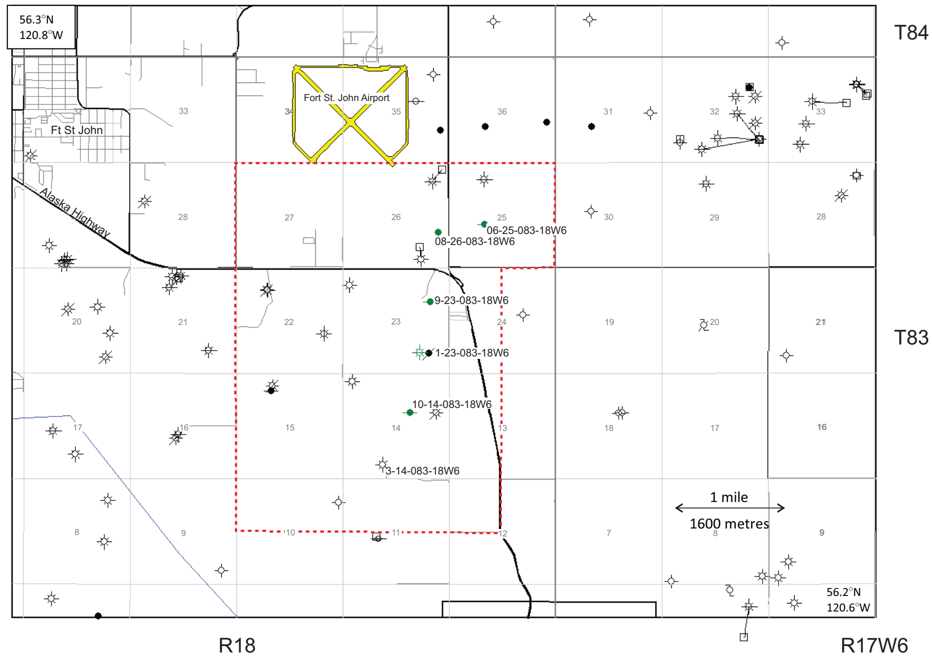

Figure 1. Fort St. John Oil Field North Pine A pool: The North Pine A pool is outlined in a dashed red line. North Pine A oil pool wells are shown by green symbols.

enough to drill along a constrained northeasterly trend. In those early reports of the 1950s, Pacific and other operators had difficulties getting good seismic data in terrain dissected by deep river valleys, and the technology was very basic then. Airborne scintillometer, magnetometer and electrical methods (along with surface mapping) formed the basis for their understanding of structure and possible hydrocarbon traps. Based on previous drilling experience, they knew that there was sandstone with good hydrocarbon potential several hundred

their original drilling licence indicates that they expected production to be from Permo-Pennsylvanian strata (now known as the Belloy Formation). The Baldonnel Formation was subsequently squeezed off and the hole was recompleted as a North Pine (formerly known as Triassic C) oil well in 1956, which produced between 1956 and 1991. Other wells followed soon after, with some of those later wells also being completed unsuccessfully in the Baldonnel Formation. Pacific was likely aware of oil shows and porosity in drillcore and cuttings from lower members of the Triassic section such as the North Pine because such wells were not abandoned despite poor results from the Baldonnel Formation or the lack of shows from the Permo-Pennsylvanian strata.

It is not entirely clear from early geological reports (e.g., Falconer, 1951[2]) why Pacific was astute

[2] Reports submitted by operators as work requirements to hold permits are available for the public to view at the office of the British Columbia Ministry of Natural Gas Development, 1810 Blanshard St., Victoria, British Columbia. Most were done in the early years of exploration, so they are mainly of historical interest; however, many contain information that could be of use to current operators. Titles and contact information for making an appointment are given in the PNG Contact Information Guide, found at: http://www.empr.gov.bc.ca/TITLES/OGTITLES/OTHERPUBLICATIONS/Pages/default.aspx

feet below the top of the Triassic section, but they did not hint at knowledge of facies or trends. Early slim holes were used successfully as a quasi-substitute for seismic surveys in the hopes of identifying large drillable structures. From those holes, they were able to obtain some stratigraphic knowledge, but only to depths of approximately 1200 ft. (approximately 365.8 m). Their surface mapping would not reveal anything about the thin-bedded Charlie Lake Formation lying several thousand feet deeper.

In 1978, Pacific was acquired by the newly formed national oil company, Petro-Canada Inc., which took over operation of the original wells in sections 14 and 23. After several other transfers of interest, the oil and gas rights for the Charlie Lake Formation eventually came to be held by Penn-West Petroleum Inc. (Penn-West). The lands on which wells were later drilled in the northern part of the pool have had a complex ownership history, but they are now operated by Penn-West as well.

PRODUCTION

Oil production began in 1956 and remained steady

TABLE 1. RESERVOIR PARAMETERS FOR THE NORTH PINE A POOL IN THE FORT ST. JOHN OIL FIELD

FORT ST. JOHN OIL FIELD

North Pine A pool

Pool Parameters

Field code: 3600 **Pool code:** 4580A
Formation: Charlie Lake, North Pine member
Discovery well original name: Pacific Fort St. John No. 9 3-14-83-18W6 **WA#:** 00034
Current operator: Penn-West Petroleum Ltd.
Rig release: July 11, 1952
Other oil and gas shows: North Pine gas, Halfway gas, Baldonnel gas
Number of wells (as of October 2012): Oil: 6 Gas: 2 Active: 2

Reservoir Data

Area of pool: 892 acres, 361 ha
Average depth of producing zone: 4350 ft., 1326 m
Lithology of reservoir rock: sandstone
Trap type: structural/stratigraphic
Estimated maximum reservoir thickness: 3.5 m
Drive mechanism: gas cap expansion
Average porosity: 13%
Average net pay: 1.5 m
Average permeability: 83 mD
Average water saturation (%): 25
Oil formation volume factor (%): 127
Gravity: 41° API
Original pressure: 1919 psi, 13 231 kPa

Reserves

Estimated original oil in place: 4 231 500 barrels, 672 734 m^3 (volumetric)
Recovery factor (%): 50
Estimated recoverable oil: 2 115 750 barrels, 336 367 m^3
Cumulative oil production: 2 080 960 barrels
Remaining recoverable oil: 34 790 barrels
Remaining original oil in place (%): 51
Cumulative water production: 171 050 barrels

until approximately 1992, with two or more wells always producing. A steady decline began circa 2000 (Fig. 2). In the past ten years, only one or two wells have been under production at any given time; the decline in production can be attributed both to general depletion and the number of producers. In the early days of pool development, individual wells could produce approximately 70 barrels/day. Recent production levels have been approximately 6 barrels/day.

Water production does not appear to have been a major problem because water cut has averaged approximately 12% over the life of the pool; this percentage has not increased greatly over time. No water disposal wells or injectors are used for this pool. Produced water is taken by truck to a disposal well operated by Newalta Corporation at location 15-5-83-17W6.

A plot of pressure survey readings (Fig. 3) for individual wells taken at different times shows a cluster along a slope of an approximate 3000 kPa pressure drop every 10 years. Pressure trend lines are subparallel for the older wells in the south end of the pool, whereas wells in the northern part of the pool exhibit a generally steeper drop in pressure over time. Some level of communication for the entire pool is suggested by the clustering of values, but a partial permeability barrier apparently impedes communication between north and south.

GEOLOGY

At the time of early development of this pool, the Triassic section was poorly understood because the area was relatively remote and few wells penetrated to that depth. As the area developed and mapping of stratigraphic equivalents in the disturbed belt provided a more 3D perspective, the Triassic section could be subdivided into formations and members. This was not easy—and is still open to debate—because the entire Triassic section is represented by a complex series of sandstones, dolomites and evaporates characterized by swift vertical and lateral changes in lithofacies. Units often have little lateral continuity; for that reason, lithofacies are difficult to correlate over distance. The lack of data also makes time correlations difficult. Even the most widely accepted time marker within the Charlie Lake Formation, the Coplin unconformity, cannot be picked within each well in the Fort St. John area. The old log suites that exist for some of the wells, consisting of micrologs and elogs, are not ideal for correlations of rapidly changing facies of thin beds. Lithostratigraphic correlations have been done for the Charlie Lake Formation largely on the basis of the gamma ray curve (e.g., McAdam, 1979). Elogs or micrologs provide only a limited ability to make lithostratigraphic correlations among thin-bedded members of the Charlie Lake Formation.

The North Pine member of the Charlie Formation

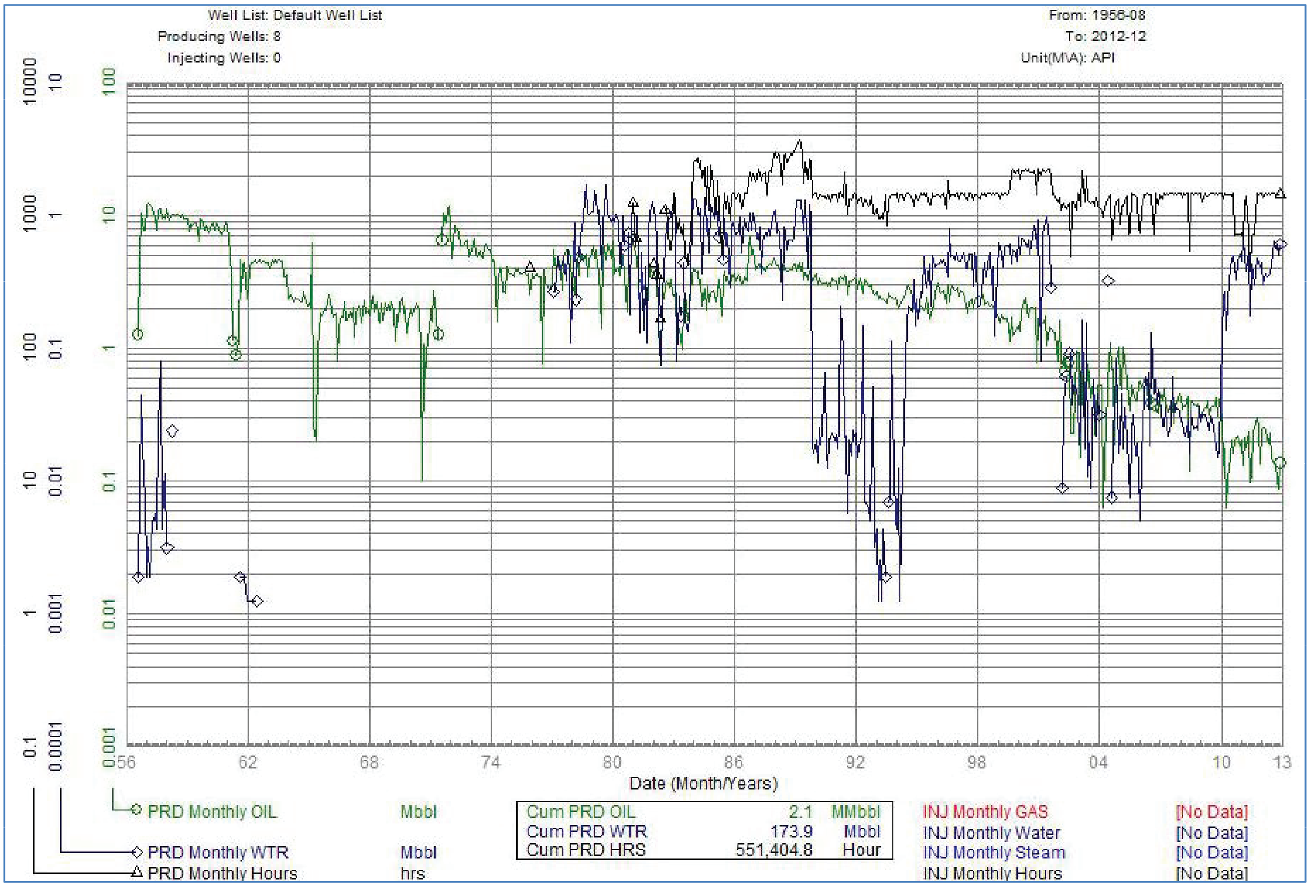

Figure 2. North Pine A oil production: This chart shows oil (green line) and water (blue line) production over the life of the pool. Oil production started in 1956, held steady until approximately 1992 and began to drop sharply in approximately 2000. The black line for hours on production indicates that two or more wells were on production most of the time (approximately 750 h/month). Data records are incomplete for water and hours production between 1958 and 1976. Upward and downward jumps in water production are largely attributable to incomplete records for some wells. The big dip in produced water between 1989 and 1995 is due to incomplete reporting for one well of the wells on production.

is thin and discontinuous, so trapping appears to be primarily stratigraphic. Seismic surveys indicate that it is truncated to the north by a fault, which appears to structurally constrain the pool in that direction. The North Pine member was deposited as a winnowed, narrow and linear shoreface sand trending north-northeast. It can be correlated along its length (Fig. 4) but becomes silty or shaly to the east or west.

The North Pine member is generally described in core and samples as a light grey or white, fine- to medium-grained, friable to well-consolidated sandstone. Porosity is variable, ranging from poor to good. Oil staining or shows are sporadic, visible in a few locations and absent in others. Appendix A provides descriptions and pictures of drill cuttings taken across the North Pine member.

Water cut is comparatively low and oil-water contacts are not evident in any wells. Overlying and underlying beds are shaly and would be neutral with respect to effects on pressure. Consequently, the highly efficient recovery factor of 50% must be largely attributable to gas cap expansion; however, without fresh input of water, a steep drop in pressure is inevitable without active intervention.

A gas-oil contact can be picked at –706 m (below mean sea level) at location 8-26-83-18W6 (Fig. 5), but it cannot be seen at the same elevation in the other pool wells. In the other wells, this elevation occurs either above or below the North Pine member. At location 6-25-83-18W6, a gas-oil contact can be seen at a depth of –713.5 m (1387 m measured depth). Gas-fluid contacts are not apparent on the elogs or

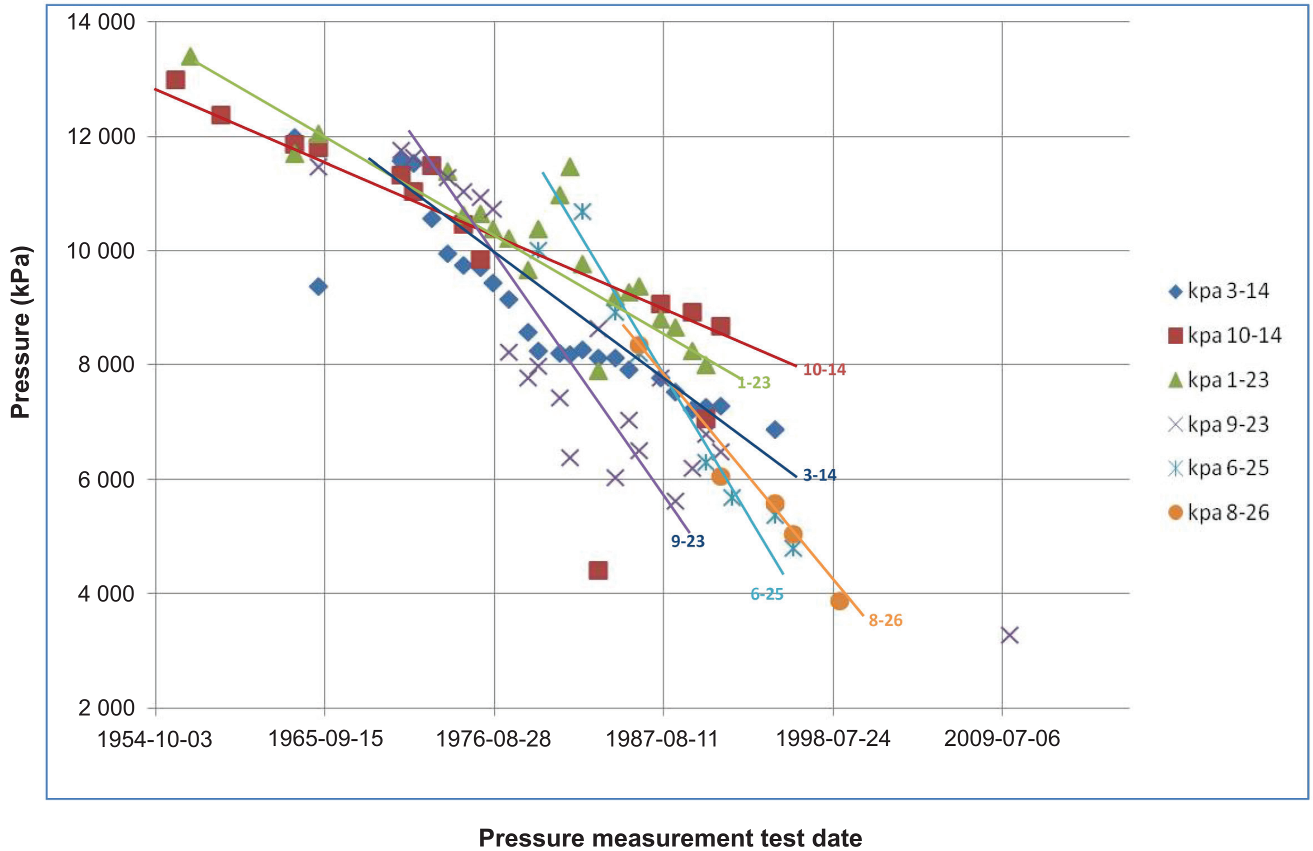

Figure 3. North Pine A pressure survey readings: The graph suggests two possible pressure regimes: northern wells (8-26, 6-25 and 9-23) show steeper drops in pressure over time than the southern wells. Pressure has dropped overall at an approximate rate of 3000 kpa every ten years. The first four wells to be drilled (3-14, 10-14, 1-23 and 9-23) indicated reservoir communication by following similar pressure drop-slope slopes for approximately the first ten years of production. The divergence between north and south slopes becomes more apparent in the early 1980s. Not many readings have been taken in the last 15 years, so little can be said about recent pressure trends. Anomalous outliers can be partly explained by unusually long or short shut-in times. Anomalous readings can also be the result of inconsistent measurement techniques.

micrologs run for the wells drilled prior to 1960. Imperfect communication among the producing wells, as demonstrated above, likely precludes the likelihood of common fluid contacts in a reservoir consisting of a thin heterogeneous sandstone occupying a narrow corridor and stretched over a long distance. Fluid contacts might at one time have been at the same elevation and then shifted with tectonic movement. On the other hand, localized contact elevations could have developed at the time of hydrocarbon emplacement as a result of imperfect communication along a long narrow and thin sandstone body.

The structure of the North Pine member shows a gentle east-southeast dip (Fig. 6). As discussed previously, a water contact is not obvious in any of the pool wells and water cut has been comparatively low, so water likely does not act as a lateral constraint. Instead, hydrocarbon distribution is probably determined by the quality of the sandstone

Twenty drillstem tests (DSTs) were run at discovery well 3-14, including one over the North Pine sandstone. The sample description contains a mention of light oil staining; as a result, although it is also described as having poor to fair porosity, it was tested. Gas (1000 mcf/d) and oil (810 ft., or 246.9 m) were recovered. The test chart (Fig. 7) is difficult to read but does indicate liquid inflow during the flow period (only one flow) but a slow buildup during shut-in, suggesting fair permeability. Shut-in and flow periods were probably too short to give a proper representation. Figure 8 shows a DST chart for location 8-26-83-18W6, where a DST demonstrated very good to excellent permeability in the North Pine member. Here the shut-in and flow periods were long enough to provide a more realistic

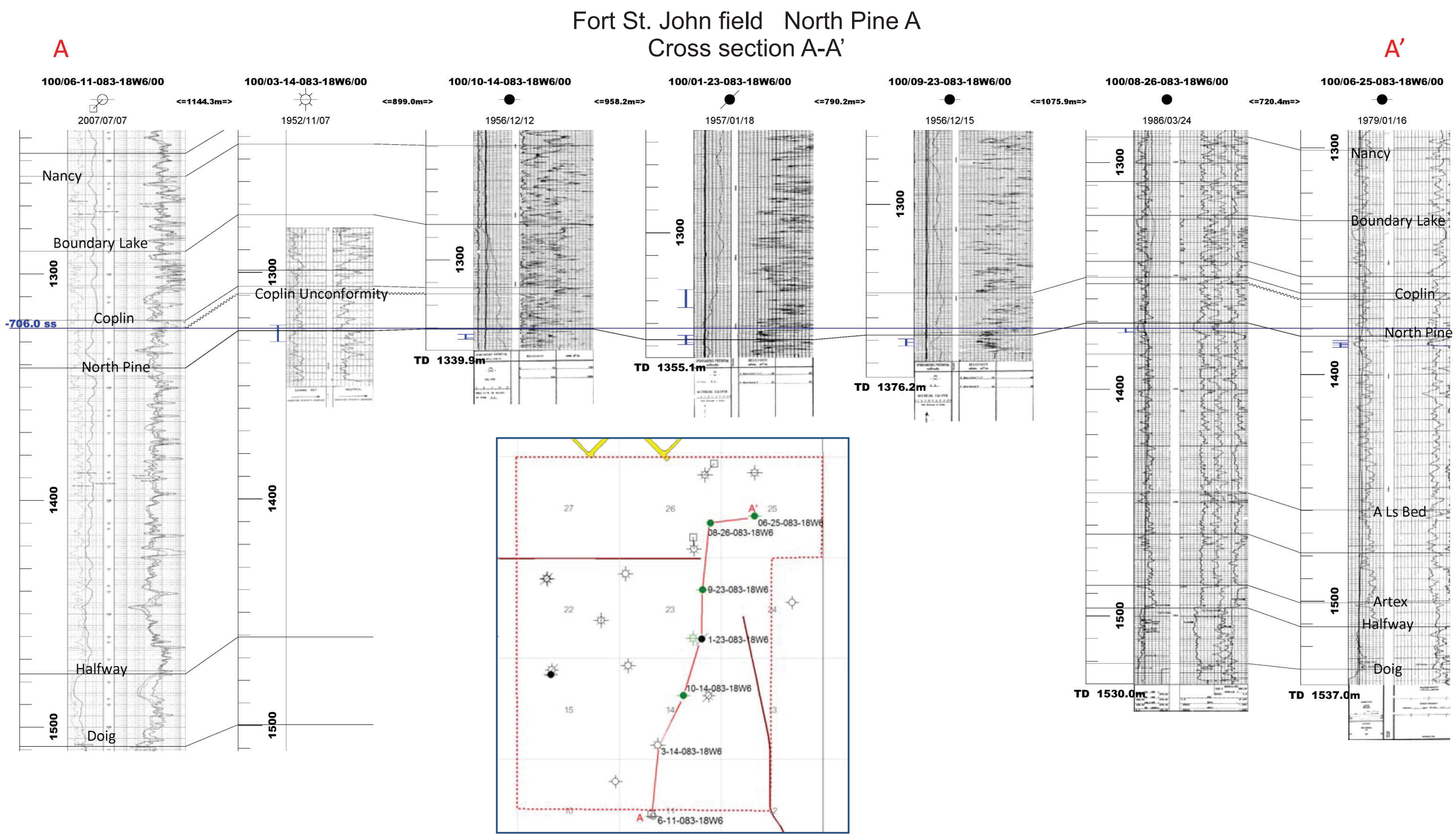

Figure 4. Structural cross-section A–A’ North Pine A pool: Structural cross-section with datum (blue line) at –706 m mean sea level (msl), which is the original gas-oil contact at 8-26. Other wells cannot share this exact gas-oil elevation because the North Pine member is below this elevation at the other wells. A gas-oil contact is present at –714 m msl at 6-25. The North Pine member can be correlated along the length of the pool as shown in this cross-section, but it is absent or poorly developed laterally.

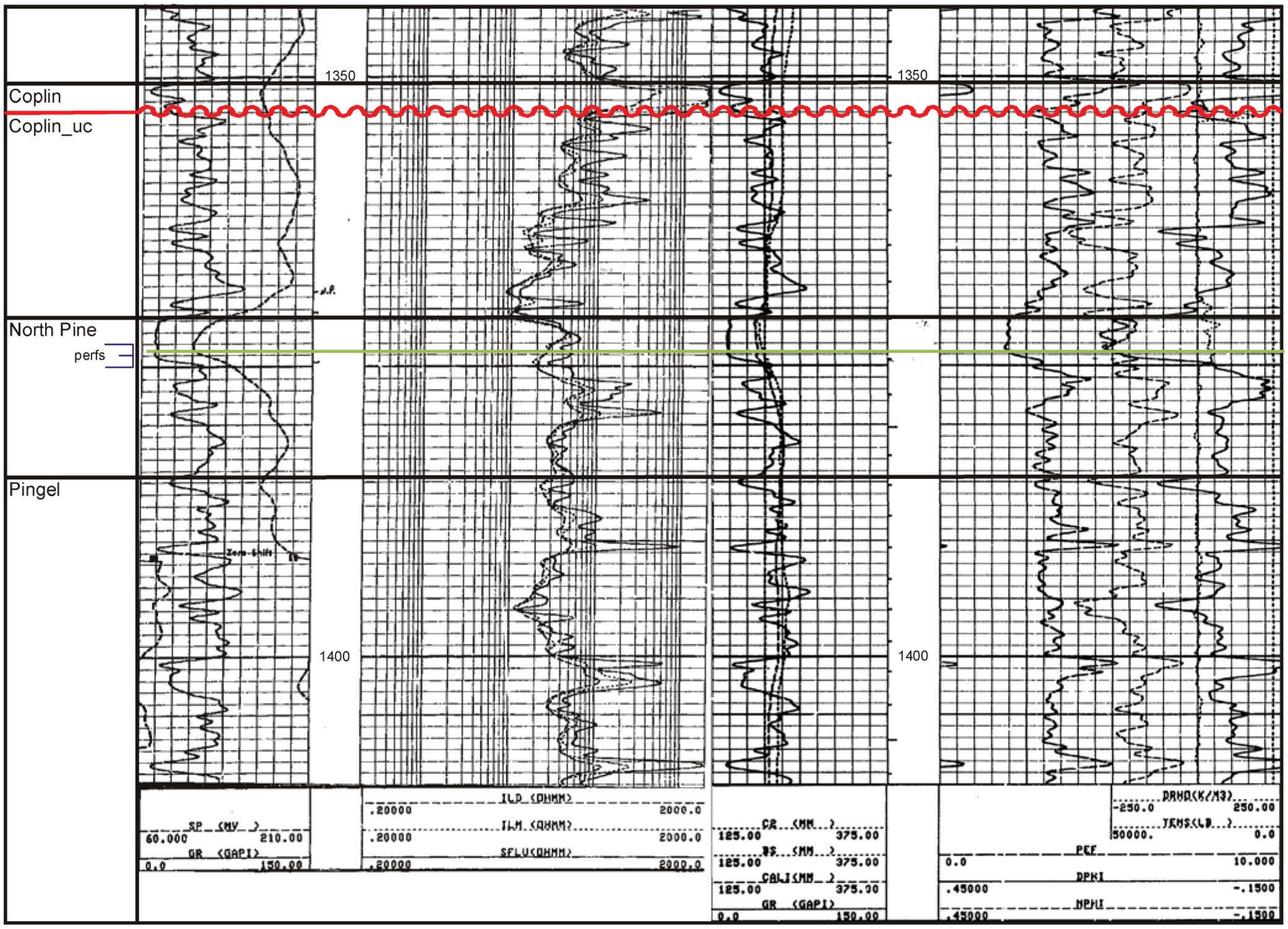

Figure 5. Location 8-26-83-18W6 induction and neutron-density logs: Neutron-density crossover in the North Pine indicates gas. This gas component has been important for the efficient 50% recovery rate of the pool. A gas-oil contact is at 1373 m measured depth (–706 m mean sea level).

picture of the North Pine member's flowing potential.

A kink in net pay contours (Fig. 9) adds some evidence that the pool could consist of two or more separate segments. The extent of oil pay is well defined to the north but more open-ended to the south. A fault might limit its southward extent (Fig. 6); however, pay could continue along trend south of the pool boundary as suggested by contouring.

OPPORTUNITIES FOR FURTHER DEVELOPMENT

A very efficient recovery rate of 50%, derived from gas expansion in a permeable reservoir, suggests that much of the original oil in place must have already been recovered. Production has declined along with pool-wide pressures. Some efficiency might be restored if pressures could be increased through a secondary recovery scheme. Good permeability in the North Pine member should permit good receptivity of water or gas injected to increase pressure, which would result in significant production gains.

The precision and resolution of modern 3D seismic surveys might be applied to extending the limits of the reservoir in an east-west direction and to the south. Some of the thicker accumulations of the North Pine sandstone might be within the resolution of new seismic technology. Although the pool extent is limited by faulting to the north, the exact placement of that boundary might leave room for another producer, or possibly an injector.

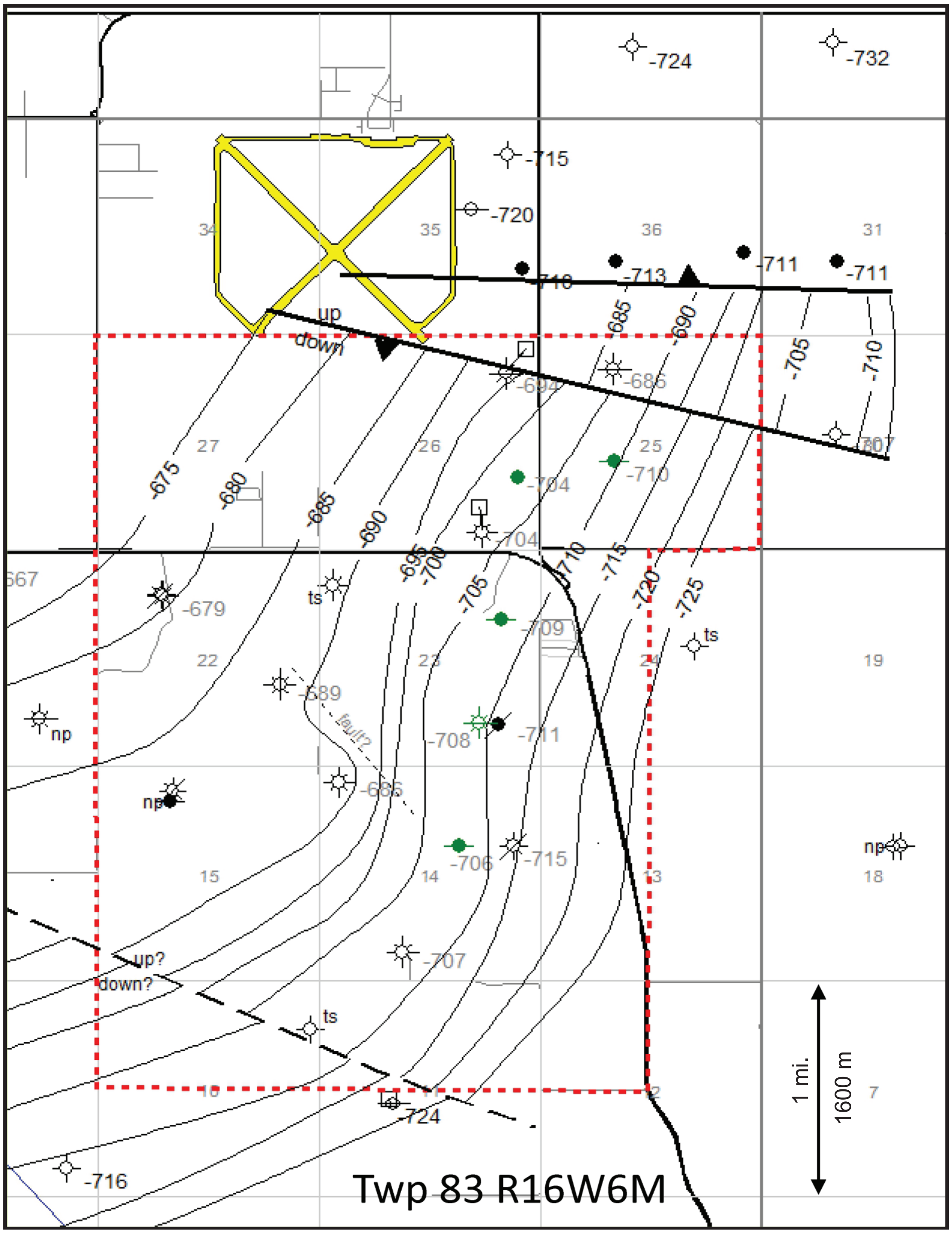

Figure 6. Structure of the North Pine member (5 m contour interval): Pool wells are indicated with green symbols and the pool is outlined in a dashed red line. The dip is to the south-southeast. Seismic evidence backs the presence of the fault limiting the pool to the north. The fault drawn at the south end of the pool is conjecturally based upon the apparent sudden drop in structural elevation near the south end of the pool. A possible small fault oriented northwest-southeast could explain the plateauing and bunching of contours in the south-central region; np = not present; ts = too shallow.

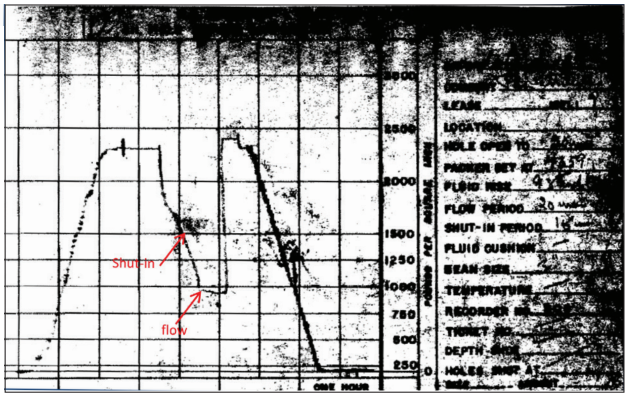

Figure 7. DST #12 (4358—4375 ft.) at location 3-14-83-18W6 (run 1952/07/04). Upward slope on flow indicates fluid. Shut-in slope indicates fair permeability. Shut-in (15 min) was not long enough for pressure to stabilize, so the test is not conclusive. Apparently only one flow period was run. Gassy oil (810 ft.) and gas (1000 Mcf/d) were recovered.

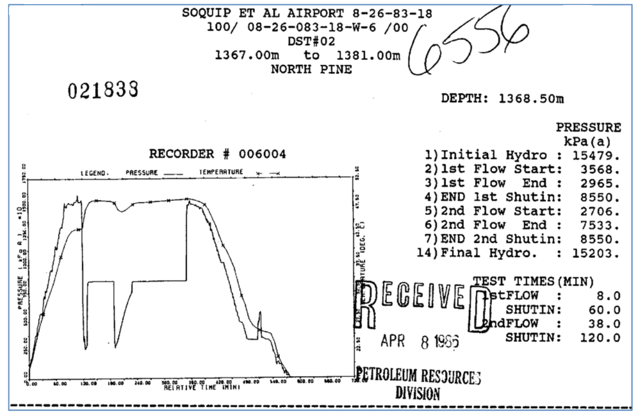

Figure 8. DST #2 at location 8-26-83-18W6. Very good to excellent permeability is displayed by almost immediate stabilization upon shut-ins. Oil (200 m) and water (100 m) were recovered.

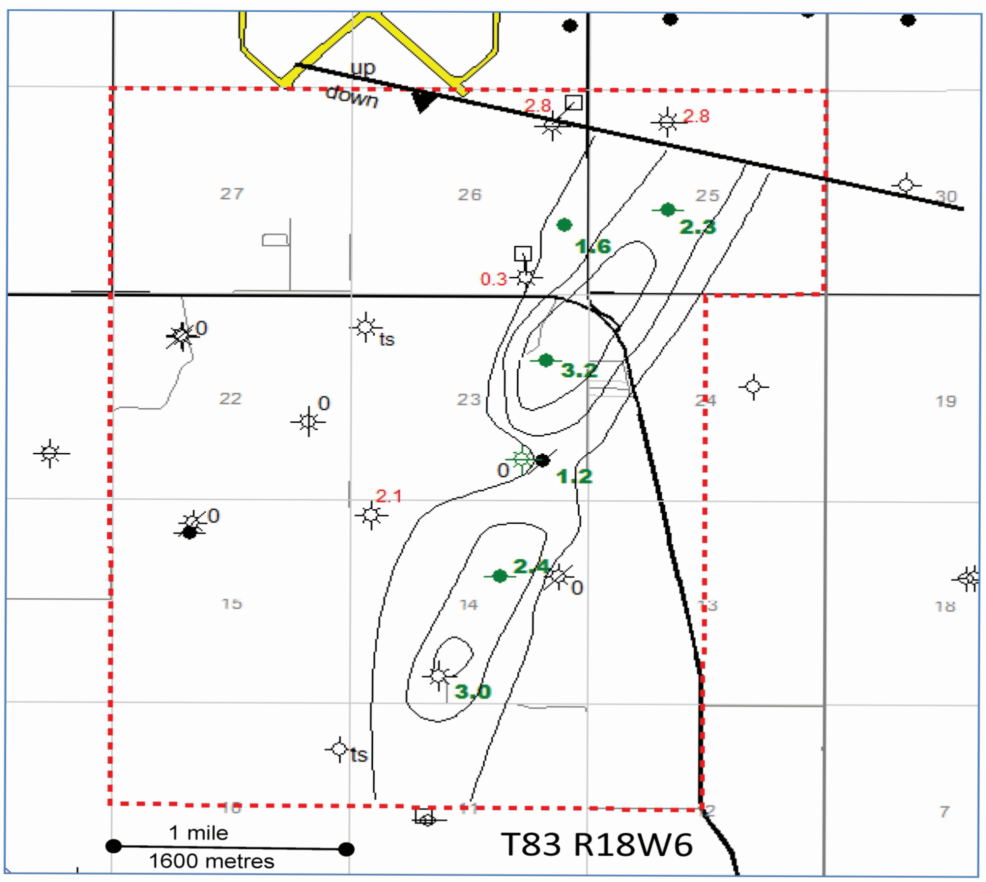

Figure 9. North Pine A pool; net oil pay North Pine member: Oil pay numbers are in green and gas pay is in red. Contour interval is 1 m net oil pay. The contours suggest a constriction in the central portion of the pool more or less coinciding with somewhat different pressure regimes between north and south. The extent to the south is not well defined. Faulting limits oil pay to the north.

ACKNOWLEDGMENTS

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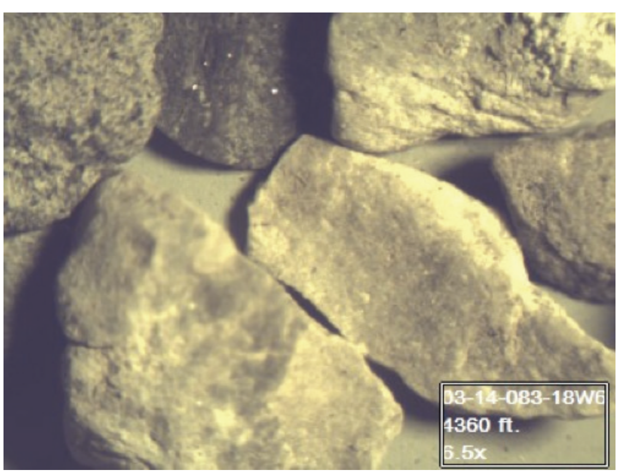
APPENDIX A

FORT ST. JOHN – NORTH PINE A

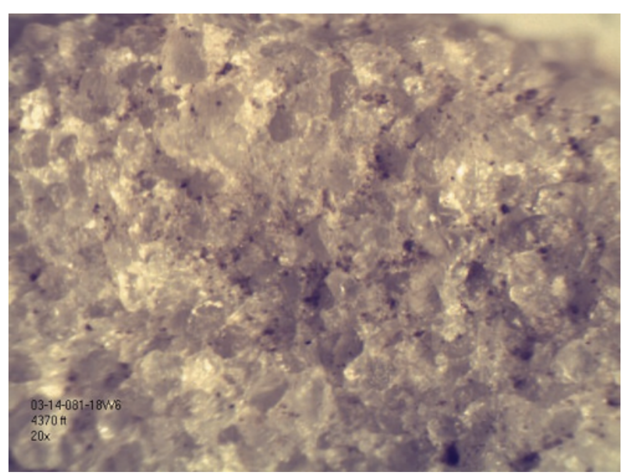
Discovery well 100/03-14-083-18W6/02

Intervals are given in feet as found on the sample vials; top North Pine member is at 4349 ft., perf interval is 4356–4365 ft.

Depth (ft.)	Description
3560–3570	Shale (100%): dark grey, soft-moderate hardness, flaky, silty, micaceous.
4060–4070	Sandstone (60%): orange, quartz arenite, very fine grained, rounded, well sorted, well cemented, dolomite cement, 15% intergranular/fracture porosity.
	Shale (40%): dark grey, silty, micaceous.
4270–4280	Sandstone (70%): white, quartz arenite, very fine grained, subangular, well sorted, well cemented, calcite cement, 7% (2% visual) intergranular porosity, micaceous, minor pyrite, trace garnet.
	Shale (25%): dark grey, hard, silty, pyrite, silica.
4280–4290	Shale (100%): dark grey, flaky, soft, micaceous, trace pyrite.
4330–4340	Shale (85%): gray, brittle, silty, fine- to medium-grained, calcareous in part.
	Sandstone (15%): white, quartz arenite, very fine to fine-grained, subrounded, locally well sorted, well cemented, calcite cement, 11% (3% visual) intergranular porosity.
4340–4350	Sandstone (75%): white, quartz arenite, very fine grained, subangular, well sorted, well cemented, dolomite cement, trace pyrite, 12% (5% visible) intergranular porosity.
	Shale (25%): dark grey, medium hardness, silty, micaceous, moderately cemented, minor silica sand.
4350–4360	Shale (80%): dark grey, silty, calcite crystallization, soft, fissile.
	Sandstone (20%): white, quartz arenite, very fine grained, subrounded, well sorted, very well cemented, calcite cement, trace garnet, 9% (1% visual) intergranular porosity.
4360–4370	Shale (70%): dark grey, silty, moderate hardness, micaceous, glauconitic.
	Sandstone (30%): white, quartz arenite, medium-grained subangular moderate sorting, well cemented, dolomite cement, 10% intergranular porosity.
4440–4450	Siltstone (60%): white to light grey, angular, well sorted, well cemented, calcite cement, quartz, 12% intergranular porosity
	Shale (40%): dark grey, silty, hard, micaceous



Selected drill cuttings from 4360' showing a fine-grained representative nature of the majority of the North Pine member. Magnification is 6X.



Close-up view at 20X magnification of a single chip. Fair to good textural relief indicates good intergranular porosity. Only minor detrital material is present among the predominant quartz grains.